

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

2322 SCOMM 96: HOUSE SPEC. COMM. ON OIL & GAS, 1995-1996

REFERENCE MATERIAL

- (1) INFORMATION OF THE EXPORT IMPORT
BANK OF JAPAN
- (2) INFORMATION OF JAPAN NATIONAL
OIL CORPORATION
- (3) INFORMATION OF THE DEVELOPMENT
BANK OF JAPAN
- (4) INFORMATION OF THE EXPORT IMPORT
BANK OF KOREA

TAGS Construction Costs and Timeline



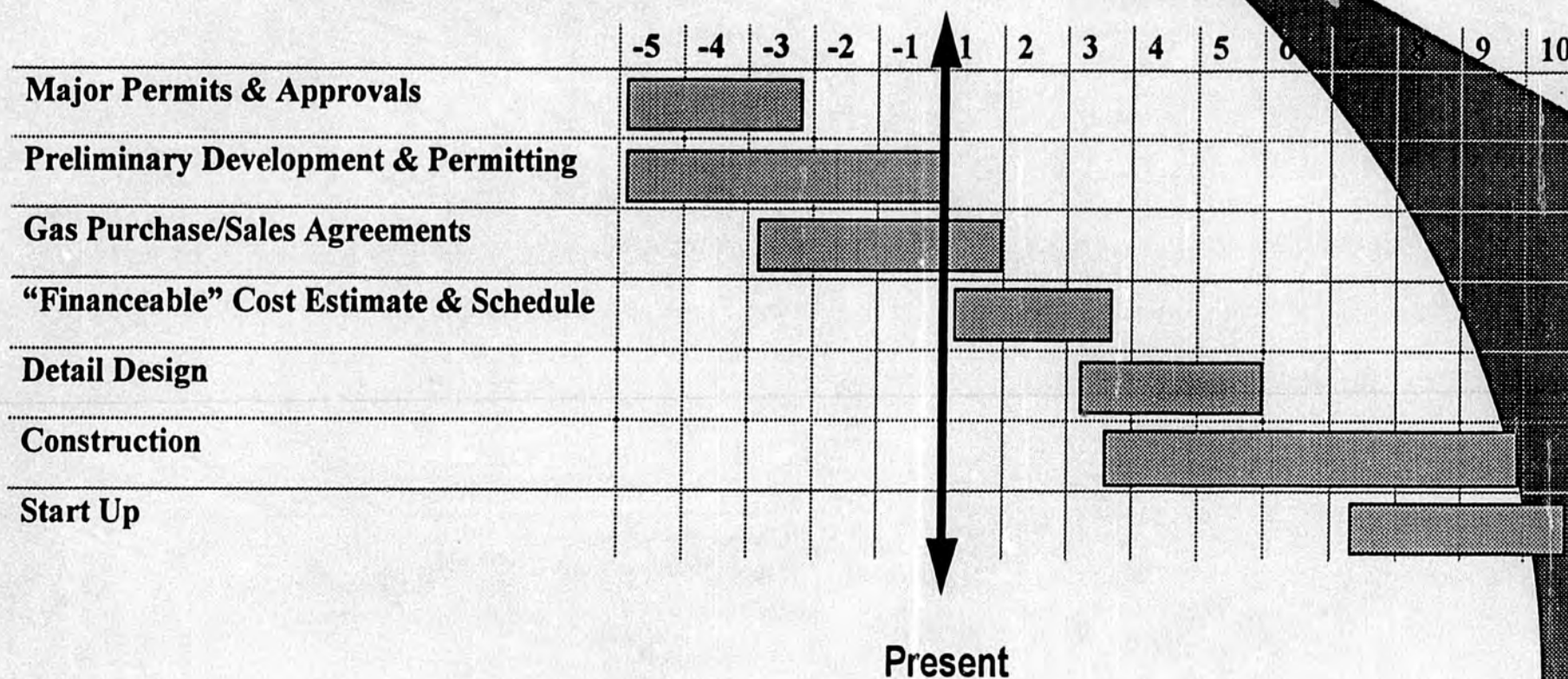
TAGS Capital Cost Estimates

(1991 \$ billions)

	<u>Total</u>
Alaska Facilities	10.0
Shipping	<u>3.4</u>
	\$13.4

TAGS Project Timetable

Y E A S



TAGS Competition:

Cost Comparisons



Grass Roots LNG Projects

Cost Comparison

Project	Production (MMTPA*)	Estimated Cost \$ Billions	Cost in \$ Billions per MMTPA	Capital ** per MMBTU
Alaska TAGS	15	13.6	0.91	0.70
TAGS at higher cost	15	15.0	1.00	0.77
Qatargas	6	6.0	1.00	0.77
Natuna Island	15	21.3	1.42	1.00
Sakhalin	6	7.9	1.32	1.01

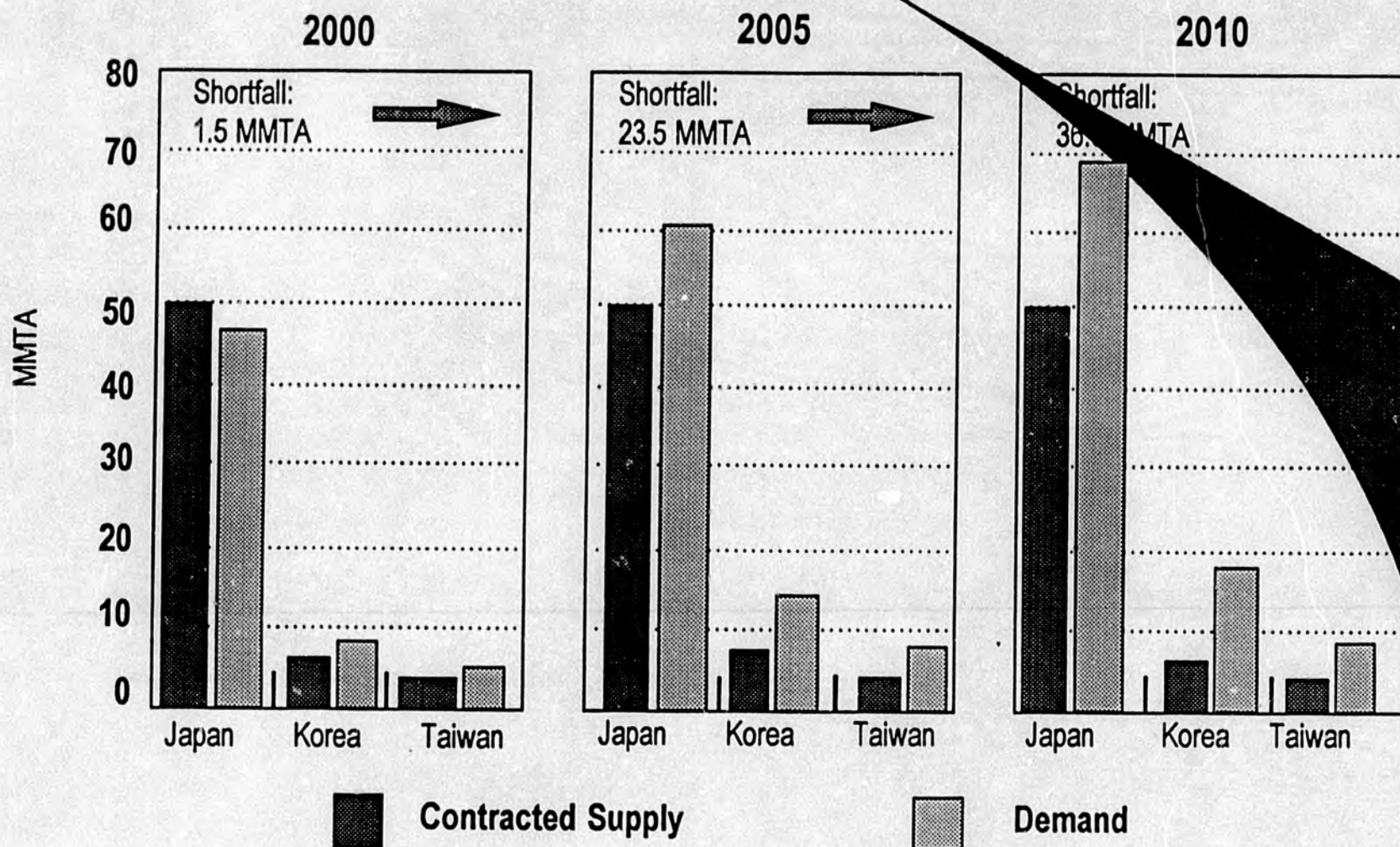
* million metric tons per annum

** does not reflect capitalized interest, cost of gas, time value of money or operating expense

Asian LNG Market: Demand Projections



Contracted Asian LNG Supply vs. Projected Demand



Financing of LNG Projects

- A Case study for Natuna Gas Development Project from a financier's viewpoint -

The Industrial Bank of Japan, Limited

IBJ

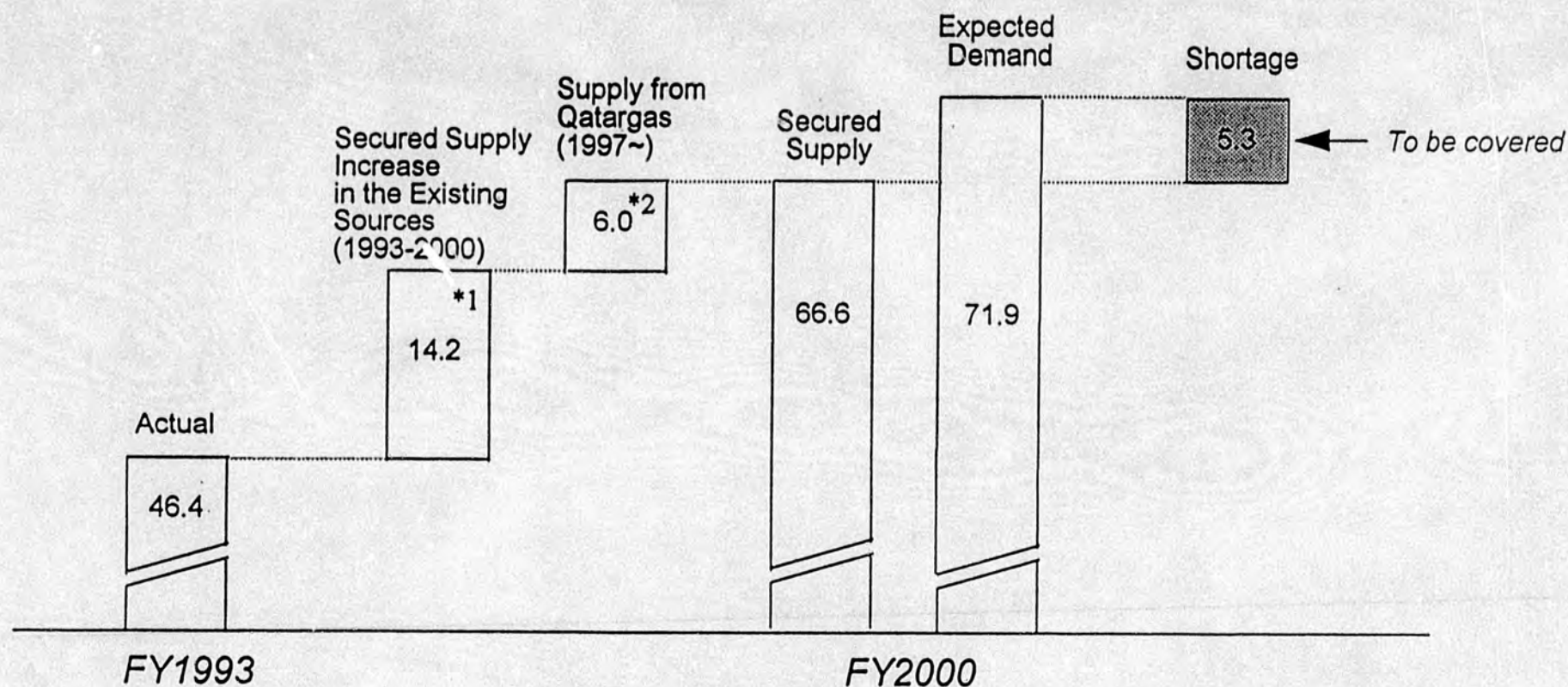
I. A Financier's view on East Asian LNG Supply and Demand

- Supply-Demand Balance Before Year 2000**

- Supply-Demand Balance After Year 2001**

Fig. 1

LNG Demand & Supply in the Far East ***-Japan, Korea, Taiwan, FY2000-*** (Million Tons)

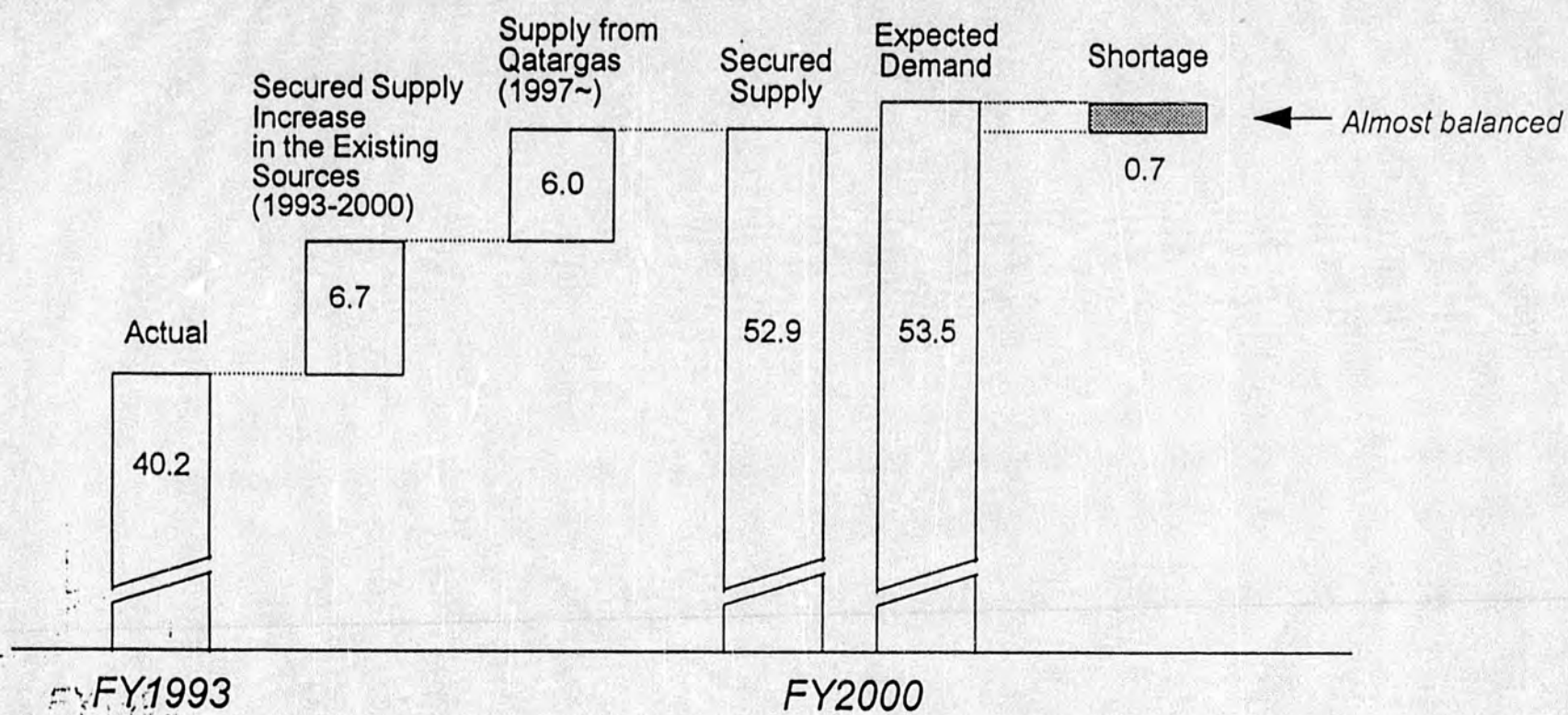


*1 Including Indonesia Badak Train H
 *2 Excluding Qatar Ras Laffan Project

<Source: IBJ Estimation>

Fig. 2

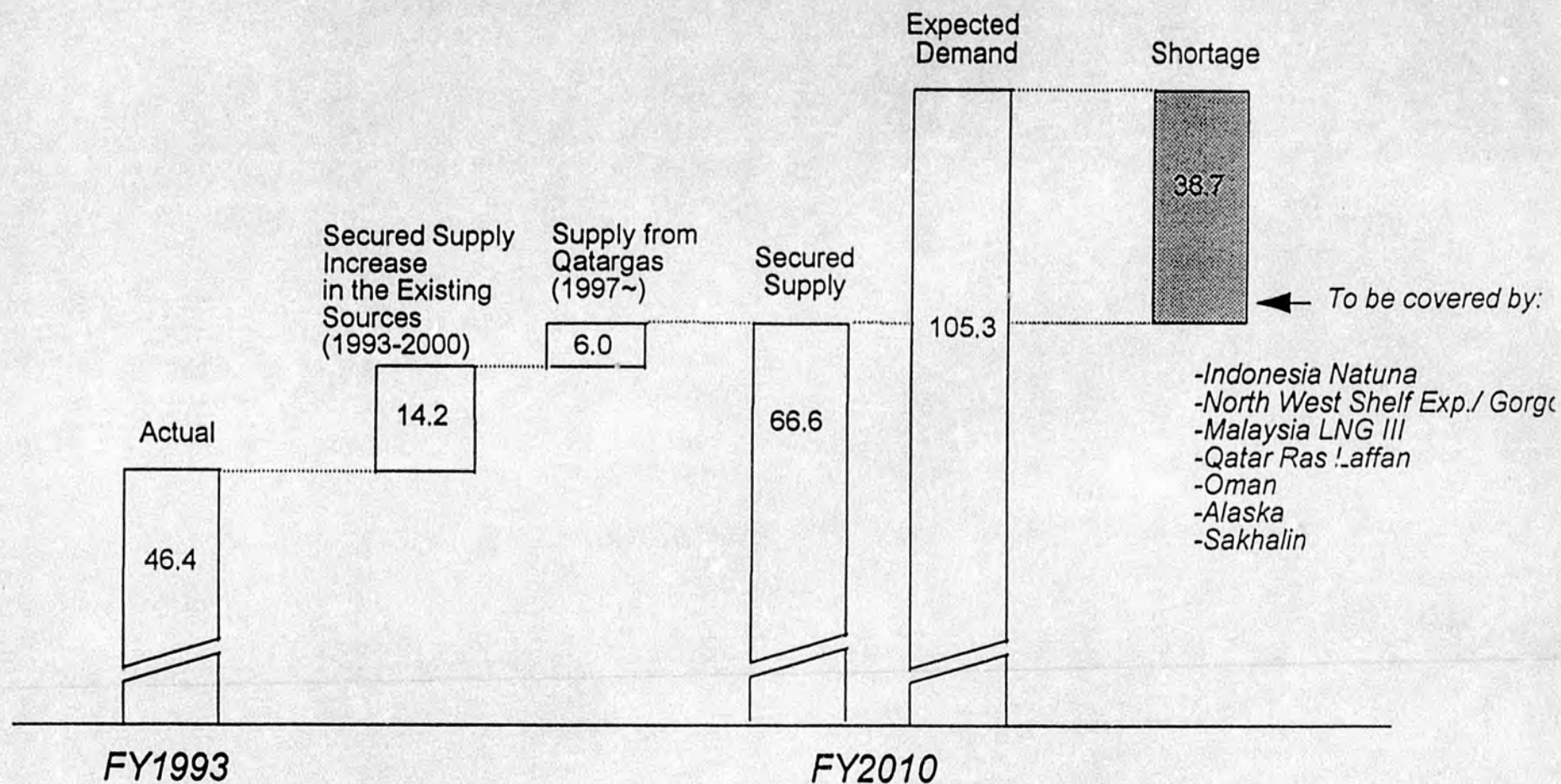
LNG Demand & Supply *-Japan FY 2000- (Million Ton)*



<Source: IBJ Estimation>

Fig 3

LNG Demand & Supply in the Far East ***-Japan, Korea, Taiwan, FY2010- (Million Tons)***



<Source: IBJ Estimation>

Fig.4

LNG Demand & Supply ***-Japan FY 2010- (Million Ton)***

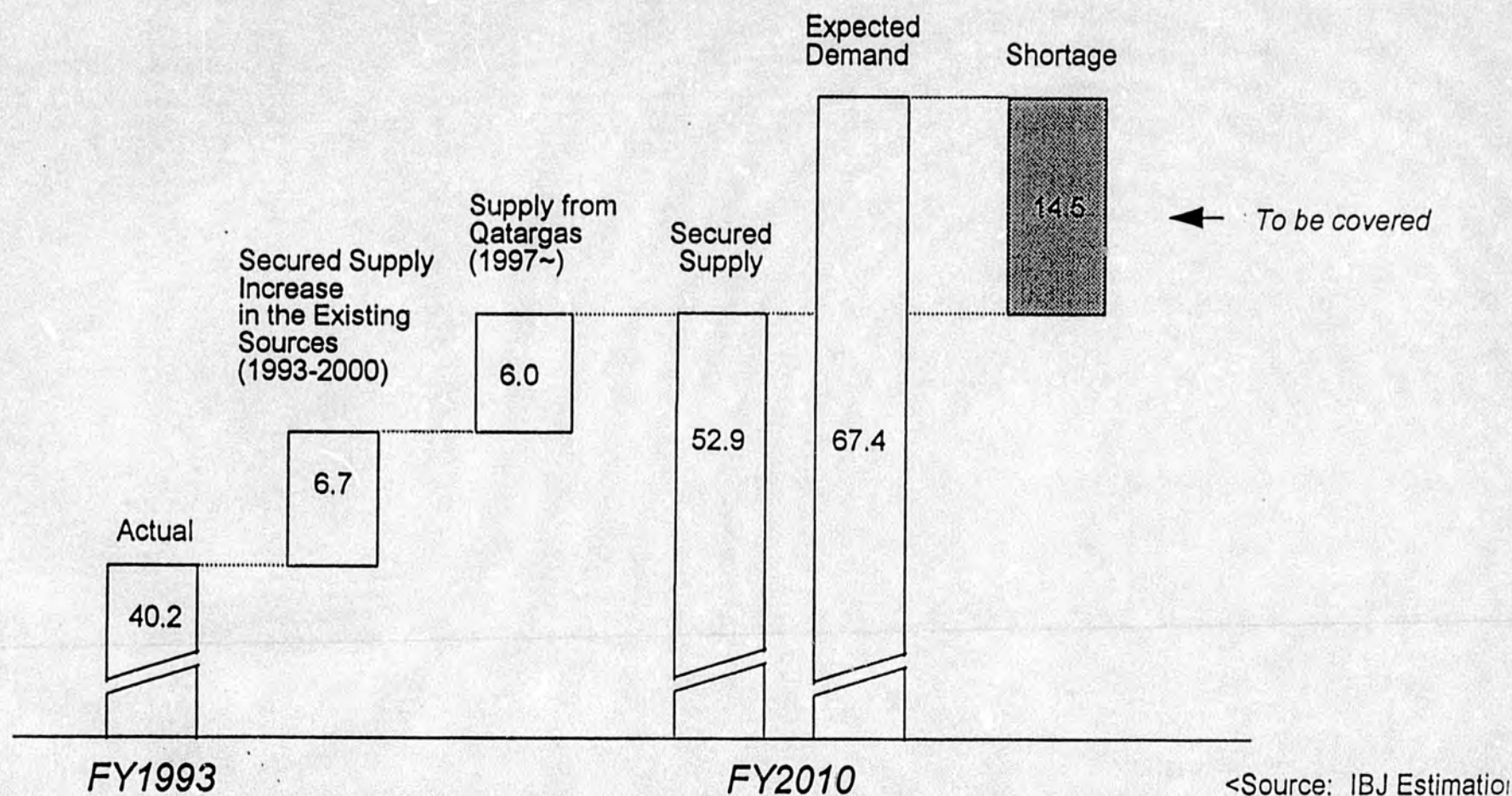


Fig. 5

Existing LNG Contracts/Commitments for 2000

As of October 1995 (Unit: Million Tons per Year)

	Tohoku Electric	Tokyo Electric	Chubu Electric	Kansai Electric	Chugoku Electric	Kyushu Electric	Elec. Cos. Total	Tokyo Gas	Osaka Gas	Toho Gas	Saibu Gas	Medium City	Gas Cos. Total	Nippon Steel	Japan Total	Korea	Taiwan	Grand Total	Expiration of SPA
Alaska		0.82					0.82	0.27					0.27		1.09			1.09	Mar-04
Brunei		3.72					3.72	1.14	0.68				1.82		5.54			5.54	Mar-13
Abu Dhabi		4.45					4.45						0.00		4.45			4.45	Mar-19
Indonesia	3.22	0.51	3.80	3.45	0.00	1.56	12.54	0.92	3.01	0.92	0.00	0.29	5.14	0.60	18.28	5.30	4.15	27.73	
(Badak/Aruni, Badak V/G)			2.15	2.57		1.56	6.28		1.30	0.25			1.55	0.60	8.43			8.43	Dec-10
(Badak II)			1.65	0.88			2.53		0.44	0.55			0.99		3.52			3.52	Mar-11
(Aruni II)	3.22	0.51					3.73						0.00		3.73			3.73	Dec-04
(Aruni III)							0.00						0.00		0.00	2.30		2.30	Nov-06
(Badak III/E)							0.00						0.00		0.00		2.25	2.25	Dec-09
(Badak IV/F)							0.00	0.92	1.27	0.12			2.31		2.31			2.31	Dec-13
(Korea II)							0.00						0.00		0.00	2.00		2.00	Jun-14
(Hiroshima/Nihon)							0.00					0.29	0.29		0.29			0.29	2016
(Badak VI/II)							0.00						0.00		0.00	1.00	1.90	2.90	2019
Malaysia	0.50	4.80	0.00	0.42	0.00	0.00	5.72	3.55	0.60	0.28	0.27	0.38	5.08		10.80	2.00	2.25	15.05	
(MLNG I)		4.80					4.80	2.75			0.21		2.96		7.76			7.76	Dec-03
(MLNG II)	0.50			0.42			0.92	0.80	0.60	0.28	0.06	0.38	2.12		3.04	2.00	2.25	7.29	Mar-15
Australia		1.05	1.05	1.05	1.05	1.05	5.25	0.68	0.68	0.21			1.57		6.82			6.82	Dec-08
Qatar (Qatargas)	0.52	0.20	4.00	0.29	0.12		5.13	0.35	0.35	0.06			0.76		5.89			5.89	Dec-21
TOTAL	4.24	15.55	8.85	5.21	1.17	2.61	37.63	6.91	5.32	1.47	0.27	0.67	14.64	0.60	52.87	7.30	6.40	66.57	

Fig. 7

Major Gas Development and LNG Projects with IBJ Involvement

Project (year / country)	Major Promoters	IBJ's Involvement
Indonesia LNG (Original) (1974, US\$1,547M)	Pertamina, JILCO (Kansai Electric Power, Chubu Electric Power, Kyushu Electric Power, others)	-Managing bank of J-EXIM joint finance for JILCO
Indonesian LNG expansion projects: -Badak (1981, US\$996M) -Arun (1981, US\$840M) -Badak Capital Investment (Phase I & II) (1986-87, US\$200M) -Badak, Train E (1988, US\$316M)	JILCO, Pertamina INALCO (Tohoku Electric Power, Tokyo Electric Power, Mitsubishi Corp.), Pertamina Pertamina Pertamina, Huffco, Total, INALCO	-Managing bank of J-EXIM joint finance for JILCO -Managing bank of J-EXIM joint finance for INALCO -Agent and lead manager of syndicated project loan -Arranger and lead manager of the trustee borrowing scheme
Malaysia LNG (Sarawak LNG) (1980, US\$1,233M)	Petronas, Shell, Mitsubishi Corp.	-Financial advisor for Petronas -Financial advisor for Malaysia LNG Sdn. Bhd. -Managing bank of J-EXIM joint finance for Petronas -Participated in J-EXIM joint finance for Mitsubishi Corp.
North West Shelf Gas (Phase I) (1981, Australia, A\$2,000M)	Woodside Petroleum Ltd. (WPL), BHP, Shell, BP, Chevron	-Lead manager of Euro-syndicated project loan for WPL
North West Shelf Gas (Phase II) (1985, Australia, A\$10,000M)	Woodside Petroleum Ltd. (WPL), BHP, Shell, BP, Chevron, Mitsui/Mitsubishi	-Lead manager of Euro-syndicated project loan for WPL -Lead manager of EXIM co-finance syndicated project loan for MIMI (Mitsui/Mitsubishi)
Thailand B Structure (1991, US\$500M)	Petroleum Authority of Thailand (PTT), Total, British Gas	-Arranger and lead manager of Euro-syndicated project loan for PTT
Malaysia LNG Dua (1994, US\$2,513M)	Petronas, Shell, Mitsubishi Corp., Sarawak State Gov.	-Lead arranger and coordinator
Qatargas (1994, Qatar, US\$2,850M)	QGPC, Total, Mobil, Mitsui & Co., Marubeni	-Core bank and lead manager



A SELLER'S VIEW OF ASIA-PACIFIC
LNG MARKET BY 2010

by

H. BAHARUDDIN

Senior Vice President
Director Corporate Affairs
PERTAMINA
Jakarta, Indonesia



FIRST DOHA CONFERENCE ON NATURAL GAS

PANEL SESSION 2 - March 13, 1995

PRESENTATION BY MR H. BAHARUDDIN
PERTAMINA - INDONESIA**"A SELLER'S VIEW OF ASIA-PACIFIC LNG MARKET BY 2010"**

Thank you very much for giving me the opportunity to exchange a few ideas with you today on the future of Asia-Pacific LNG market. You will not be surprised if I start my remarks today by saying that I anticipate a bright future for LNG exports as far as we can see forward, that means between today and 2010.

I. A BRIGHT FUTURE FOR LNG EXPORTS

LNG merits in terms of economics and environment are being recognized by a growing number of government planners and industrial investors in this part of the world. I therefore believe that at least 3 countries - China, Thailand and India - will soon follow the example of Japan, Korea and Taiwan, and become LNG importers in a very near future.

LNG demand forecast in Asia-Pacific

Japan will remain by far the biggest LNG buyer in the world. 14 Japanese companies are or will soon be importing LNG. In 1993, Japanese LNG imports came close to 40 million tons, 47% of which supplied by Indonesia.

To assess future demand, we can use MITI's long term plan which seems to me rather on the low side when it comes to LNG : 53 to 54 million tons in the year 2000 and 58 to 60 million tons in 2010. These projections assume a 2% per annum growth in LNG demand for power generation and a 4% per annum growth in LNG consumption by city gas companies.

One major Japanese trading company is sharing the same view regarding city gas while expecting a higher growth - above 3% per annum - in power generation LNG use. This, I believe, is a more likely demand scenario : 61 or 62 million tons in 2005 and 70 million tons in 2010.

The second biggest LNG importer in Asia-Pacific region is Korea. Korea Gas Corporation is using itself 2 demand scenarios which appear very reliable. These scenarios are running until 2006 and therefore need some extrapolation. The forecast is as follows : 11 to 13 million tons in the year 2000, 14 to 17 million tons in 2005, and maybe 18 to 21 million tons in 2010.

Assessing Taiwan future demand is more difficult due to the uncertainty regarding new power plant projects. LNG, coal, nuclear, what will be their respective shares in the year 2000 is still unclear. If we exclude any new LNG-fired power plant after 1999, Taiwan LNG imports could rise to 6 or 7 million tons and remain at this level. However, based on existing development plans for LNG-fired power plants, the forecast could reach much higher figures : 9 million tons in 2005, and 12 in 2010.

Among the new LNG customers in Asia-Pacific, China probably offers the biggest potential. Up to 2 million tons of LNG could be imported in the Southern provinces as early as in the year 2000, rising to 4 to 8 million tons in 2005 and 8 to 16 million tons in 2010. Uncertain forecast, indeed, but looking at the current economic growth and the huge size of its population, China is deemed to become a big LNG player.

Thailand's LNG requirement will obviously depend on the availability of domestic gas resources and pipeline alternatives. Imports are planned to start in 2001 and could reach 3 to 5 million tons in 2005, 6 to 10 million tons in 2010.

In India, a number of LNG projects is reported but LNG development needs to be compared with the economics of importing gas by pipeline from the Middle-East. The minimum case could see no LNG import until 2010, while the maximum case could be 4 million tons in 2005 and 10 in 2010.

In summary, I would assess Asia-Pacific LNG imports as follows:

- between 70 and 75 million tons in the year 2000,
- about 85 up to 105 million tons in 2005, and
- a wide range of approximately 100 to 140 million tons in 2010.

It means a lot of potential ... and also a lot of uncertainty!

However, demand figures cannot be discussed independently from supply forecast. Demand does not depend only on consuming countries' plans but also on the availability of reliable and economical resources on producers' side.

Supply and demand gap

Based only on existing capacity and taking into account the possible depletion of some gas fields, the supply from the 6 existing Asia-Pacific LNG producing countries should remain around 50 million tons over the period 1995 - 2010.

The most economical way to reduce the gap with demand is probably through the expansion of existing capacity. Such plans are underway or under review and could add another 14 million tons in the year 2000, increasing to about 21 million tons through the period 2005 - 2010.

It gives us, over the period 2000 - 2010, a total Asia-Pacific LNG supply between 65 and 70 million tons from the existing plants including their projected expansion.

This will not be sufficient to meet the rising demand. With expansion projects only and without grass-root projects, our forecast shows that the supply and demand gap would reach 4 to 9 million tons in the year 2000. This gap would then further increase to a range of 15 to 35 million tons in 2005 and 25 to 45 million tons in 2010.

These figures are big and challenging for the LNG industry. It is clear that several grass-root projects will have to be developed in the coming years to overcome the supply and demand gap. No less than 10 grass-root projects are in today's picture, some of which are mega-size projects, such as Natuna and Qatar.

I am not here to discuss the comparative chances of all expansion and grass-root projects in the world. I shall leave this task to independent analysts.

As for Indonesia, our aim is to balance the increase of our LNG exports with the satisfaction of growing domestic gas requirements. I would like to give you now a very brief overview of our current LNG development plans.

Indonesian projects

First, we plan to expand the capacity of our Bontang LNG plant on the Eastern coast of Kalimantan. This expansion, supported by the increase of our gas reserves in this area, will enable us to extend our first two long term contracts with Japan.

Then, our next challenge will be to extend all our other long term contracts and to supply new markets in and outside Indonesia. For this, we plan to build a new LNG plant on Natuna Island with a capacity of 15 million tons. This project is very ambitious, specially in terms of financing requirements and technological innovations. We are planning a start-up in 2005, at a right time to ease the growing supply and demand gap.

In any case, the success and timing of development for any grass-root project will depend on what slice of demand it can secure, and when. What is certain today is that all these new projects will require a lot of efforts and imagination from the part of their developers in order to be both economically viable and competitive.

II. THE VIABILITY OF NEW LNG CHAINS

Rising cost and increased value

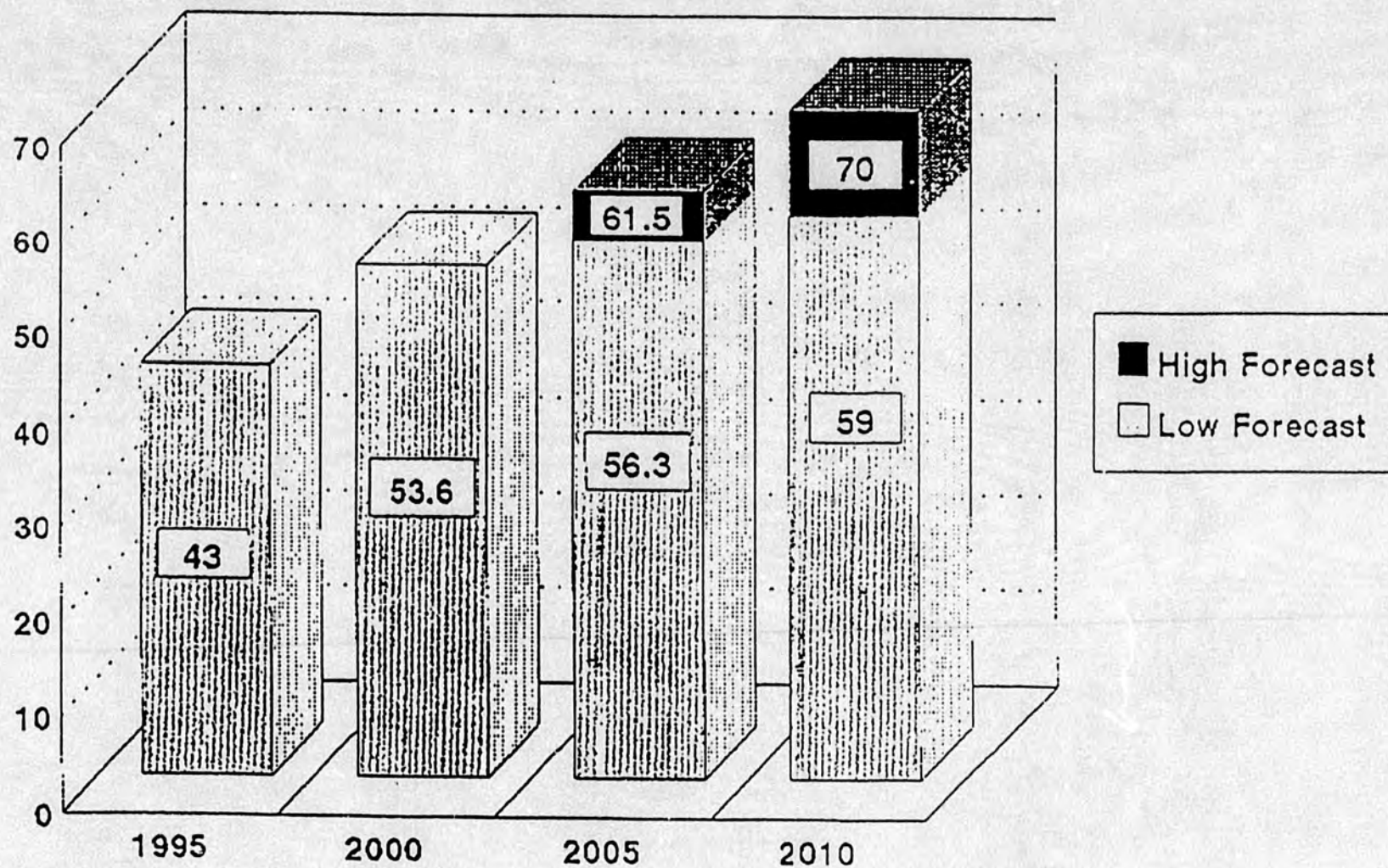
My intention here is not to enter into the detail of a subject well known by all the participants: the rising cost of new LNG projects and the increased value of LNG in the market.

These discussions tend to be usually one-sided, sellers claiming that they are justified to seek a price increase and buyers stressing the necessity for LNG to remain competitive versus other sources of energy.

Obviously, in this debate, everybody is right to a certain extent. What really matters is to seek the optimum price which can satisfy both parties' concerns. But the negotiation of a higher price is necessarily limited. Imagination and a spirit of innovation are also required, in order to explore new areas.

JAPAN LNG DEMAND

Million Tons

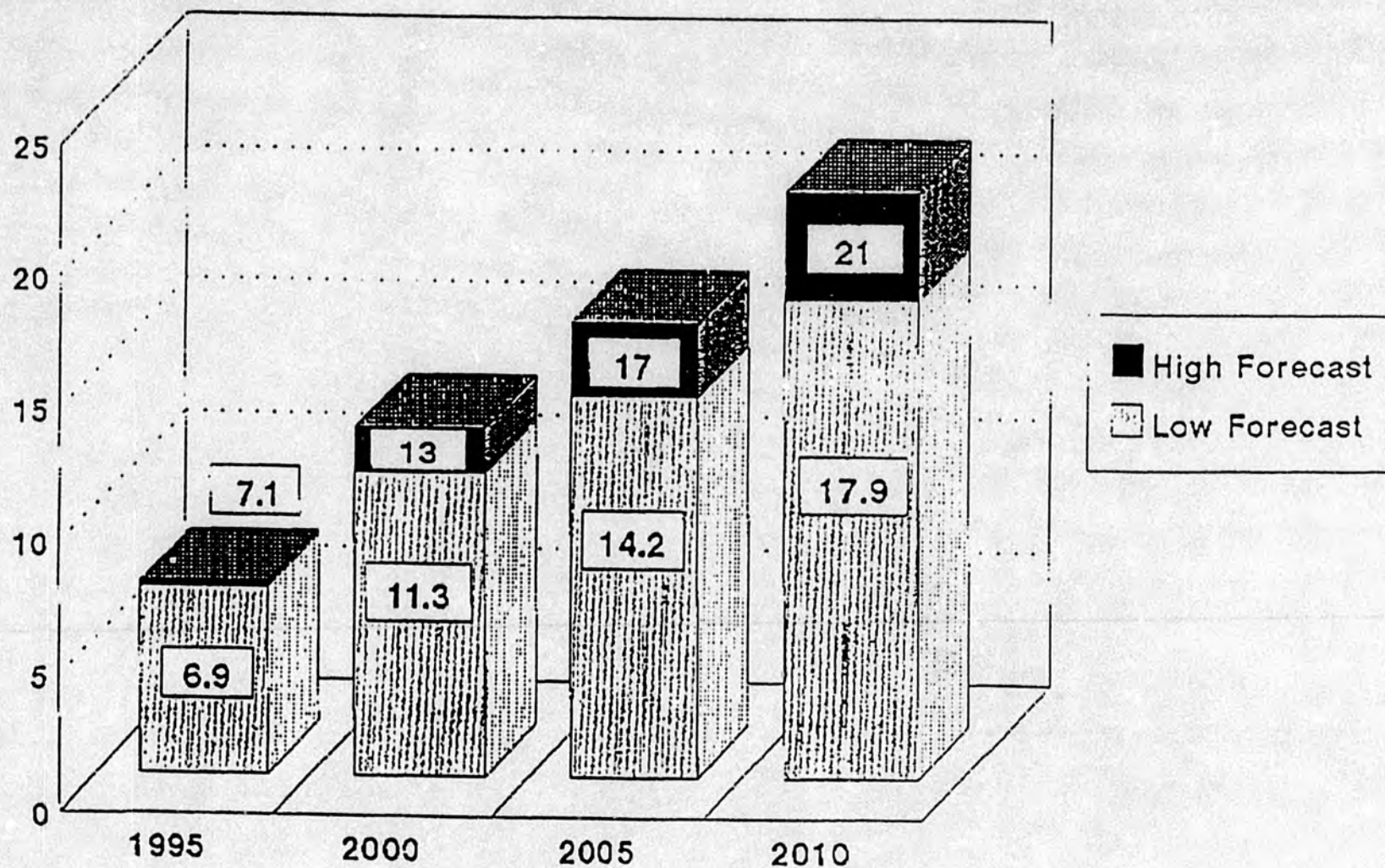


PERTAMINA

March 1995

KOREA LNG DEMAND

Million Tons

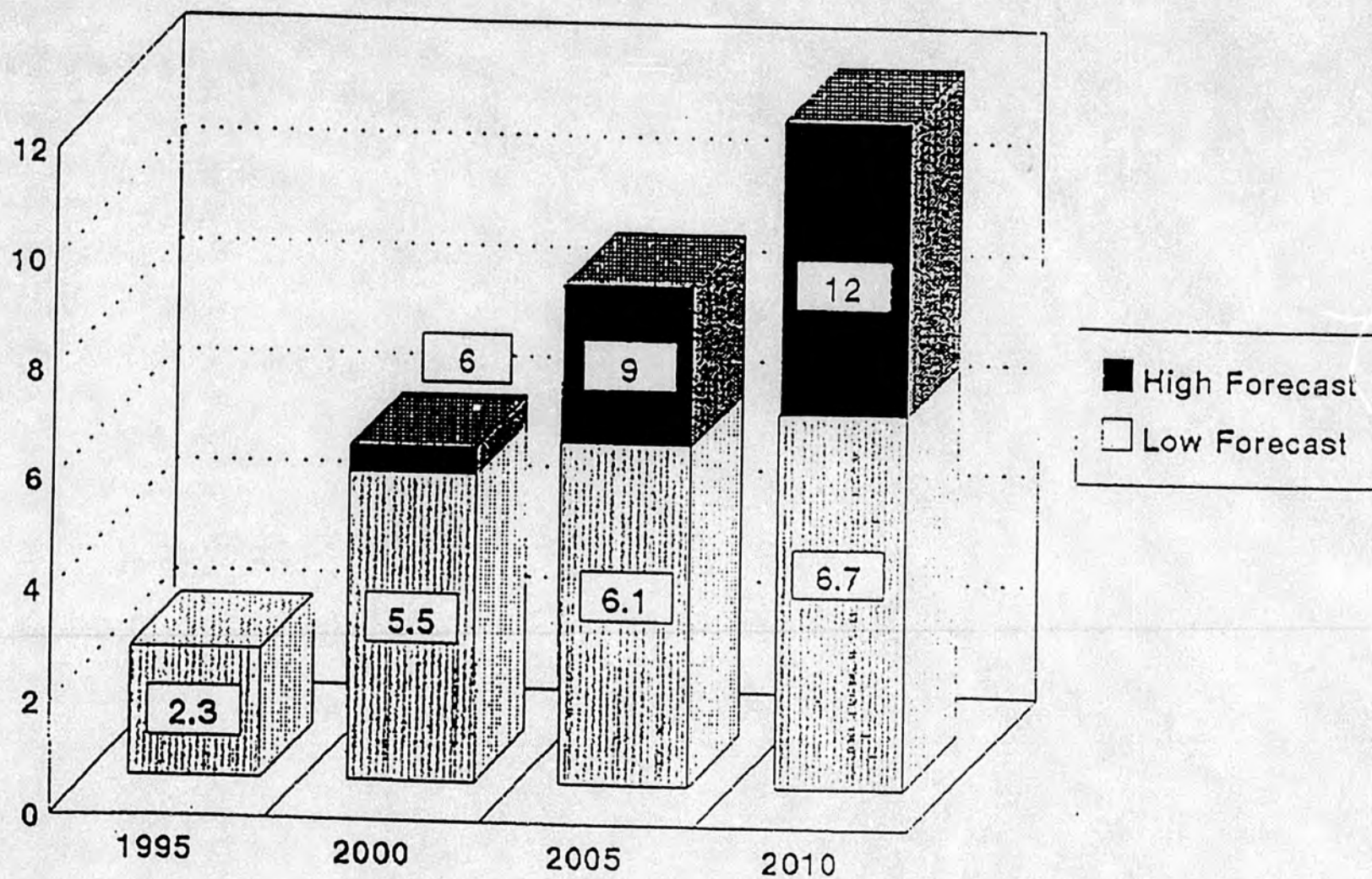


PERTAMINA

March 1995

TAIWAN LNG DEMAND

Million Tons

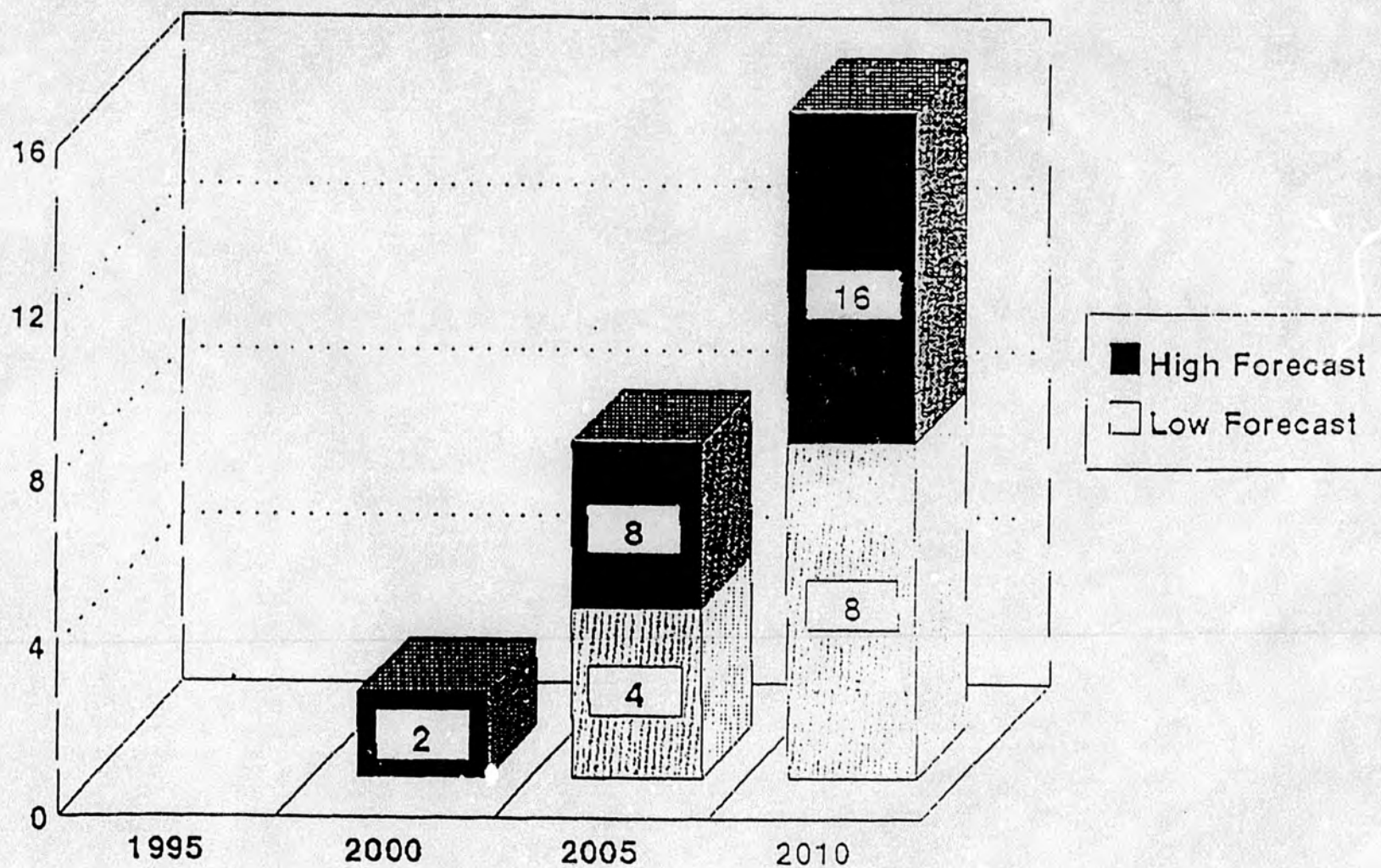


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March 1995

CHINA LNG DEMAND

Million Tons



PERTAMINA

March 1995

TABLE 1
ANALYSIS OF ASIA-PACIFIC LNG MARKET BY 2010

	Low Demand				High Demand			
	1995	2000	2005	2010	1995	2000	2005	2010
Probable Demand								
Japan	43.00	53.60	56.30	59.00	43.00	53.60	61.50	70.00
Korea	6.90	11.30	14.20	17.90	7.10	13.00	17.00	21.00
Taiwan	2.30	5.50	6.10	6.70	2.30	6.00	9.00	12.00
China			4.00	8.00		2.00	8.00	16.00
Thailand			3.00	6.00			5.00	10.00
India							4.00	10.00
Total Demand	52.20	70.40	83.60	97.60	52.40	74.60	104.50	139.00
Firm Capacity								
Abu Dhabi	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30
Alaska (Kenai)	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
Australia	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00
Brunei	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50
Indonesia	26.00	26.00	22.00	18.00	26.00	26.00	22.00	18.00
Qatargas		6.00	6.00	6.00		6.00	6.00	6.00
Malaysia	10.50	17.00	17.00	17.00	10.50	17.00	17.00	17.00
subtotal	54.50	67.00	63.00	59.00	54.50	67.00	63.00	59.00
Unmet Demand/(Excess Supply)	-2.30	3.40	20.60	38.60	-2.10	7.60	41.50	80.00
Possible Expansions & Grass-Roots Projects								
Expansions								
Australia (Perseus)			2.00	2.00			2.00	2.00
Indonesia - Badak		2.60	5.00	5.00		2.60	5.00	5.00
Qatargas		4.00	4.00	4.00		4.00	4.00	4.00
Grass-Roots Projects								
Alaska (TAGS)			6.00	14.00			6.00	14.00
Australia (Peter/Tern)			2.00	2.00			2.00	2.00
Malaysia III			6.00	6.00		6.00	6.00	6.00
Natuna			6.00	15.00			6.00	15.00
Oman			6.00	6.00		6.00	6.00	6.00
Qatar - Ras Laffan			6.00	10.00			6.00	10.00
Sakhalin I			6.00	6.00			6.00	6.00
Sakhalin II				6.00				6.00
Yemen				5.00				5.00
Possible Supplies	0.00	6.60	49.00	81.00	0.00	18.60	49.00	81.00
Excess Capacity	2.30	3.20	28.40	42.40	2.10	11.00	7.50	1.00

Norway's landing operations, but their utilization of pipeline capacity of under 50% is far lower. Originally designed to land gas from major gathering pipelines jutting into the North Sea, the three principal terminals are part of a plan that aims to stimulate offshore development, but could also be harnessed, albeit with substantial investment, as yet another beach head for spot gas sales from the North Sea. For now, though, potential producers claim that monopoly customer Gasunie's price terms are too low to warrant increased exploration and production, and no plans to connect additional UK sector fields are currently near fruition (WGI Nov.10,p4). Last year sales through the three principal terminals totaled 2.5-bcm, representing only 40% of capacity. The system brings Wintershall's Windermere gas from the southern UK North Sea to the Continent. The Uithuizen terminal serves the 36-inch

NOGAT gathering pipeline owned partly by Occidental. The Callantschoog terminal serves the NGT and WGT gathering lines and a 24-inch pipeline from the K-15 field. The Maasvlakte terminal serves Amoco's offshore P-15 oil and gas assets.

While pale in comparison to the potential influence of Norway, the Netherlands, and the UK, Denmark's facilities near Nypro in Jutland are also being expanded to accept additional Danish gas. Chances for imports from other countries are considered remote but still possible. Expansion of terminal facilities at Nypro to nearly 10-bcm/yr should be completed by Jan. 1997 to take new flows from the Harald and Trym fields. Purely a standby treatment facility and metering point, the Nypro plant is tailored for production on the Danish continental shelf, which stood at 4.6-bcm/yr, or 450-million cf/d, in 1994.

Korean LNG Demand Surges Beyond Expectations

In what is a most welcome development for aspiring liquefied natural gas producers worldwide, rapidly expanding urban gas use and burgeoning electric power needs are powering South Korea's LNG demand well beyond previous expectations. State Korea Gas Corp., now preparing its biennial forecast, is expected to show a substantial rise

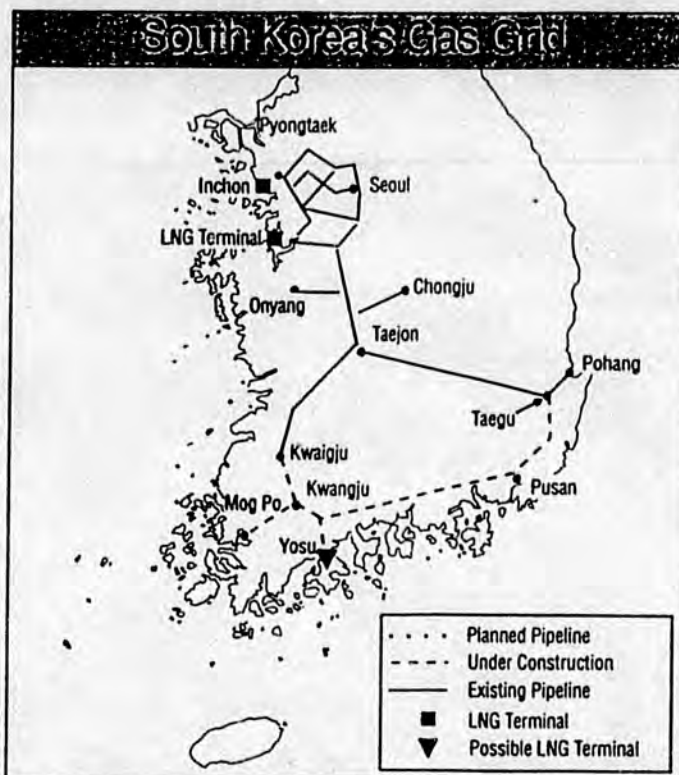
in LNG imports to more than 15.5-million tons a year by 2000 — almost triple 1994 consumption levels. Only two years ago KGC predicted, as a mid-point case, that Korean gas use would rise to 12.1-mmt/yr by 2000, based solely on LNG imports. The company is now revising its figures in a report that is to be formally released by end-year, and the preliminary conclusion from this crystal-ball gazing exercise shows a substantial increase in the country's potential gas demand. State utility Korean Power, a key incremental buyer, has yet to add its final input, but the message is clear — the potential gas needs of South Korea are far outrunning most previous predictions by LNG analysts. From 1990's level of 2.33-mmt, imports more than doubled by 1994 to 5.86-mmt. By 2000, they should more than double from year's estimated 6.86-mmt to 15.5.

The new forecast is some 28% above levels predicted in 1993 and exceeds that year's "high growth" scenario by 1-

mmt/yr. It is remarkable that for the first time ever, this year's city gas use, which is mainly residential but also commercial, almost equals South Korea's gas consumption for power generation. According to Korean analysts, city gas should account for 53.5% of all gas use by 2000. What is notable about the consumption boom is that resi-

dential city gas use, under a massive government program to substitute oil with piped gas for space heating, still has further room to expand. While power generation should soon be replaced as the top use for LNG, future incremental demand growth should also begin to develop in non-traditional consumption sectors. Korea Gas Union General Secretary Ho-Kyong Kim, in a recent paper presented in Jakarta, predicted that non-power gas use would continue to rise, supported by the need for further air conditioning during Korea's torrid summers and the expansion of gas use for transport in order to cap Korea's growing urban air pollution problems. In 1994, city gas accounted for 41.8% of Korea's 5.86-mmt/yr of gas demand.

Residential demand made up two-thirds of city gas use in 1994, and of that total some 80% was used for home heating. But Korean authorities do not believe this represents a mature market now that nearly one-half of urban



households have access to gas by pipeline. The KGU predicts "a great increase in city gas demand in chilling" for office air conditioning (all new office buildings must be led with gas) and ice storage. Further, Kim points out, as pollution controls become ever more severe, natural gas powered vehicles will have to be encouraged to improve air quality levels. Presently, Korea already uses only unleaded gasoline and is reducing diesel sulfur levels to 0.1% in 1996, and 0.05% by 1998. The government is expected to promote natural gas vehicles actively in metropolitan Seoul by 2000 in order to maintain cleaner air standards.

The boom in gas use reflects a concerted government emphasis on building gas transport, storage, and utilization infrastructure. Construction of Korea's second LNG receiving terminal is under way, and completion of a further expansion of the national pipeline network is now slated for 1998. A three-tank expansion is ongoing at KGC's Pyongtaek LNG terminal near Seoul, and another berth is under construction. This should comfortably allow for the annual import of up to 8-mmt of LNG. A second LNG terminal, at Incheon, also near the capital, should be completed by end-1996 and allow for an additional 4-mmt of imports. A third terminal, long under consideration, is now being mulled over for Yosu, at the southern tip of the peninsula.

The original nearly 1,600 kilometer national gas transmission system should be completed by 1996, and small but substantial additions to the original plan are scheduled to be finished by 1998. They include a high pressure foot diameter pipeline to the northern part of metropolitan Seoul, where incipient gas demand already has outstripped supplies. In addition, a similar high-pressure line to Taegu in the southeast is planned as well as one to Kwangju at the southwestern end of the peninsula (see map). Some 25% of South Korean households in the countryside are presently sold an LPG/air mixture in a tank, which is likely to be grad-

ually phased out as the natural gas pipeline system is completed. South Korea has built a national gas pipeline system in less than a decade, under original cost estimates, across rugged terrain, and has coped with extreme seasonal climate variations — a feat that compares quite favorably to any other country's efforts in Asia.

Swinging The Balance Of Buying Power

With such ambitious growth plans spreading throughout Korea, the balance of LNG buying power is shifting away from Tokyo and toward Seoul. This presents KGC with both opportunities and problems. The state gas company finally must move to secure further long-term base supply and cannot content itself with trolling for cheap spot LNG cargoes. The sustained buildup of Korean LNG use has been nothing short of spectacular. Growth rates in the next decade are less certain, but if LNG imports were to increase by only 50% through 2005, Seoul would already be importing more than 23-mmt. In 1993, KGC's 3.9-mmt/yr of imports represented slightly under 10% of Japanese consumption. If Mitsubishi's forecast of Japanese demand in 2000 is accurate and Tokyo imports 50-mmt — which some forecasters think is optimistic — Korean purchases would still be nearly one-third of those made to Tokyo.

Korea is gaining so much critical mass that it should soon be able to guarantee the purchasing baseload needed to launch substantial capacity increases in LNG facilities. Yet KGC must change its thinking if it is to achieve this goal. Even if all present memorandums of understanding result in firm supply contracts and if present forecasts of Korea's gas needs for 2000 are correct, KGC needs to commit to at least one new 2.5-mmt/yr train immediately, and a second one of similar capacity by 2000. That's a tall order for any company.

Monopolistic Gazprom Pushes For Competitive Markets In Europe, On Its Own Terms

When forming a list of Europe's biggest proponents of market liberalization, Russia's Gazprom, which is the world's largest gas monopoly and is determined to stay that way, hardly seems a likely catalyst for change. But with an aggressive campaign to expand its downstream, Gazprom has surprisingly emerged as one of the most important drivers of the seemingly relentless march toward gas-on-gas competition in Europe. Although the firm is making some sacrifices in terms of prices, its aggressive push into Western Europe through new pipeline infrastructure, joint-venture marketing, and co-sponsorship of the UK-Belgium Interconnector shows that in a perfect Russian world, this high-risk ploy of choosing price over profit will help Gazprom dominate the European gas market. Competitors Algeria and Norway have taken a much different approach, trying to expand the

status quo by signing up more and more long-term take-or-pay contracts. However, the much-heralded Interconnector linking the deregulated, low-priced UK gas market with continental Europe is expected to bring further competitive pressure to bear on continental gas markets when it comes on stream in 1998 (p7). Gazprom's eagerness to develop direct access to as many delivery points as possible in Europe implies the firm's recognition that even under a more liberal market, being there from the beginning is a distinct advantage.

As US and UK experience has shown, the most profitable role to play in an increasingly competitive environment is that of marketer. With that in mind, Gazprom has decided to bite the bullet by teaming up with new players to compete head-on with established European buyers — many of which have long-term sales contracts with the Russian giant. In the past five years, Gazprom has set up

Session 1

**Diversification of Gas Supply
- A View from Korea**

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Diversification of Gas Supply - A view from Korea

- 1. Natural Gas Demand Outlook In Korea**
- 2. New Environment for LNG Industry In Korea**
- 3. LNG Import and Contract Status**
- 4. Potential Export LNG Projects**
- 5. Trans-Asian Natural Gas Pipeline Study**
- 6. Conclusion**

1. Natural Gas Demand Outlook In Korea

Since natural gas was introduced to the Korean energy market, the natural gas demand has been increased rapidly over the years. The main consuming sectors are power generation and residential use owing to the government's strong commitment to environmental protection. In the industrial sector, consumption of natural gas is expected to increase steadily with the extension of the supply pipelines and intensified regulations for environmental protection.

Korea is continuing the construction and expansion of new LNG receiving terminal and the nationwide transmission pipeline network for natural gas transportation covering most of the nation's territory as its supply zones. By 2000 when the network is completed, the nation will see that almost all the city gas distribution is provided with natural gas. This conversion from manufactured city gas to natural gas will be the main cause of the acceleration of demand growth in natural gas during the remaining years of the century.

After completion of the nationwide pipeline network, increased demand of natural gas will be foreseen in the sectors of direct heating/cooling systems for commercial buildings and co-generation for plants and business buildings. In parallel with the construction of pipeline network, Korea will continue to construct large scale combined cycle gas turbine power plant. Thus the increased demand of natural gas will be expected in the power generation sector as well.

As shown in the table 1, The role of natural gas in primary energy supply of Korea will be steadily increased and take a share of about 10.5% of the total energy market by 2010 from the current share of 3.9% over the period. The share of oil, which currently occupies a predominant position in the structure of the nation's primary energy consumption, will be lowered to 53%.

Due primarily to the government's policy of lowering Korea's dependence on oil and its move towards increased use of gas as a fuel for power generation for environmental reasons, the gas consumption is expected to increase over the foreseeable future.

Table 1. Outlook for Primary Energy Mix in Korea

Fuel	Year 1992 (Actual)	1997	2000	2010	Growth rate of yearly average '90-'00 '01-'10	
Oil, MM Bbl	514.2 (61.8%)	704.5 (60.8%)	768.9 (58.4%)	905.1 (53.0%)	5.2%	1.7%
LNG, MM ton	3.5 (3.9%)	9.9 (7.9%)	13.9 (8.8%)	21.6 (10.5%)	17.2%	4.4%
Coal, MM ton	26.2 (14.9%)	42.2 (17.2%)	48.4 (17.3%)	59.9 (16.5%)	8.8%	2.2%
Anthracite, MM ton	13.6 (5.4%)	5.5 (1.5%)	3.6 (0.9%)	1.2 (0.2%)	-15.7%	-10.4%
Nuclear, MM kWH	56.5 (12.2%)	72.4 (11.2%)	97.4 (13.2%)	171.4 (17.9%)	7.0%	5.8%

Source : KEEI, Long-term Energy Outlook, April 1994.

Note : () is the component ratio.

As seen previously, the share of natural gas out of Total Primary Energy Supply (TPES) is forecasted to grow from 3.5 million tons (or 3.9 percent of TPES) in 1992 to 21.6 million tons (or 10.5 percent of TPES) in 2010. The growth rate of yearly average is expected 17.2 % over the period 1992 - 2000 and 4.4 % over the period 2000 - 2010.

The high growth of natural gas share will mainly depend on both of the extension of nationwide transmission pipeline network and the environmental concerns and policies that will make it difficult to use oil and coal for electricity generation.

The baseline projection in Table 2 and Figure 1 shows that natural gas demand is expected to grow up to 11.4 million tons in 1998 and 13.9 million tons in 2000, then to 17.9 million tons in 2006.

Table 2. Natural Gas Demand Outlook

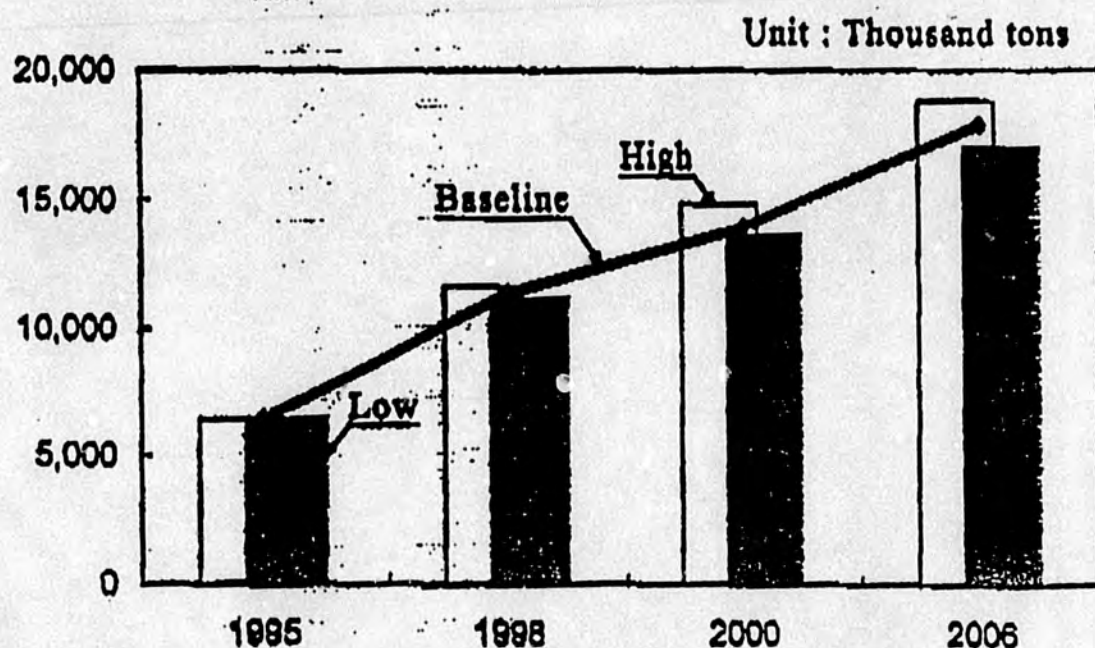
Unit: Thousand tons

	1995	1998	2000	2006
Baseline projection	6,453	11,410	13,950	17,900
Low demand scenario	6,453	11,170	13,600	17,000
High demand scenario	6,453	11,640	14,840	18,800

Source : Korea Gas Corporation.

2010
21.6 = 3.7
mtpa
1.2256

Figure 1. Natural Gas Demand Outlook



The baseline projection represents the compromised results of current trends in city gas consumption and the technical allowances for the construction periods of planned gas-fired power plants. The high and low projections then represent the progressive and conservative estimates respectively, for the period.

2. New Environment for LNG Industry in Korea

In 1993, the Korean government established a new economic development plan that will allow participation of the private sector in Social Overhead Capital (SOC) projects such as natural gas supply and electric power generation. The Government has made related decrees and regulations for the implementation of SOC projects by private sector.

The Government also amended the regulations of foreign capital inducement law to allow the foreign investors will participate in the SOC projects, including LNG import and private power generation. (Only joint investment is allowed in case of power generation)

On the occasion of private sector's participation in SOC projects, private enterprises will enter into the LNG industry, such as the construction and operation of LNG receiving terminal and regasification facilities and electric power industry as well, to become new independent power producers.

Though Korea Gas Corporation is the only LNG importer currently operating in Korea, private enterprises, such as Daelim, will become the potential importers under new business environment for LNG industry in Korea, who are planned to construct and operate the integrated LNG receiving terminals and combined cycle gas turbine power generation plants. Korea Electric Power Corporation (KEPCO) is another potential importer, who has been purchased the required natural gas from Korea Gas Corporation. KEPCO consumed some 2.5 million tons of natural gas in 1994 for gas-fired power generation and they are going to increase the use of natural gas for combined cycle gas turbine power plant, and in some existing oil-fired power plant that were and will be changed the fuel oil by natural gas.

3. LNG Import and Contract Status

Table 3 shows Korea's LNG import for each year since the first import in 1986. Korea imported 5.93 million tons of LNG from three countries in 1994. Some 5.37 million tons were imported from Indonesia under two long-term contracts. 291 thousand tons were imported from Malaysia under a short-term contract while 271 thousand tons of LNG were purchased on a spot order basis from Brunei.

Table 3. LNG Imports by Sources

Unit : Thousand tons

From	'86	'87	'88	'89	'90	'91	'92	'93	'94
Indonesia	117	1,682	2,063	2,014	2,291	2,642	3,191	4,108	5,366
Malaysia						58	117	290	291
Australia								56	
Brunei									271
Total	117	1,682	2,062	2,014	2,291	2,700	3,308	4,454	5,928

In 1995, Korea plans to import 6.4 million tons in a total of 118 shipments. This will consist of 4.93 million tons from Indonesia, 840 thousand tons from Malaysia, 728 thousand tons from Brunei under each contract summarized in Table 4 LNG Contract Status and 112 thousand tons will be imported from Australia and other countries.

Table 4. LNG Contract Status

From	Quantity	Period	Remarks
Indonesia	2.3 million ton/year	'86 - 2007	CIF
	2 million ton/year	'94 - 2014	FOB
Malaysia	2 million ton/year	'95 - 2015	FOB
Brunei	1.68 million ton/year	'94 - '96	CIF

The summary of long-term and short-term contracts for LNG imported to Korea is presented in the above Table 4.

The first long-term (20 years) contract for the procurement of LNG to be imported to Korea was concluded in August 1983 with Pertamina of Indonesia. It was for the importation of 2.3 million tons of LNG annually over the period 1986 - 2007 and the LNG is supplied from sixth train at Arun, Indonesia. A further contract for an additional 2 million tons per year from Indonesia over the period 1994-2014 was signed in May 1991.

In addition, another contract was executed to import 2 million tons of LNG annually from Malaysia over the period 1995 - 2015. The price terms of the first contract is based on CIF, while the latter two contracts are based on FOB. Korea also made with Brunei a short-term contract for 1.68 million tons of LNG during 3 years (1994-1996).

As shown in Table 5 below, the contracted volumes are almost keep up with the import requirements of LNG until 1998. However, Korea's projected LNG requirements of 13.9 million tons in 2000 are well excess of contracted volumes of 8.3 million tons from Indonesia, Malaysia and Brunei. In the long term, additional contracted volumes from grassroots LNG projects are necessary to keep up with the increased LNG import requirements of Korea.

Table 5. Contracted volumes and Import requirements

Unit : Thousand tons				
Year	'96	'98	'99	2000
Import requirements	9,198	11,057	12,627	13,512
Contracted volumes				
- Indonesia	5,812	6,364*	6,812	5,300
- Malaysia	2,428	3,299*	2,786	2,000
- Brunei	700	700	1,000	1,000
Balance to be contracted	258	694	2,029	5,212

Note : * marked volumes included about 1.5 million tons of LNG import under short-term contract from Indonesia and Malaysia.

Source : Ministry of Trade and Industry, 1995

4. Potential Export LNG Projects

There are a number of potential LNG projects under consideration. However, The question of when the new projects will be materialized and realize the production will depend on the interplay of many factors, especially delivery cost and reserves.

Table 6 shows the potential export LNG projects that will be able to export to Korea. I briefly review the potential LNG projects from the standpoint of diversification of natural gas supply to Korea.

Table 6. Potential Export LNG Projects

Project	Type of project	LNG Plant Capacity MM ton/Y	Year of First Production	Distance km
ASIA-PACIFIC				
Australia				
Gorgon	Grassroots	4 - 6	2005	7,200
North Shelf	Expansion	2.5 - 5	2000	7,200
Bonaparte	Grassroots	5	2015	7,200
Indonesia				
Badak G	Grassroots	2.5	1997	4,400
Natuna	Grassroots	7 - 14	2002	4,400
Malaysia				
MLNG III	Expansion	5	2000	4,200
Brunei				
Brunei	Expansion	2.5	2003	4,200
Papua New Guinea				
Gulf of Papua	Grassroots	5	2010	
Russia				
Sakhalin II	Grassroots	6	2005	2,200
MIDDLE EAST				
Qatar				
Qatargas	Grassroots	4 - 6	1997	11,500
Ras Laffan	Grassroots	6 - 10	1999	11,500
Oman				
Oman LNG	Grassroots	6	2003	11,300
NORTH AMERICA				
Alaska				
TAGS	Grassroots	7 - 14	2005	7,300

Recently, Korea Gas Corporation committed to purchase 2.4 million tons of LNG annually based on FOB basis over 25 years starting 1999. It is reported the price terms are not concluded yet. There is another option for another 2.5 million tons a year proposed by Qatar.

✓ Korea has recently signed a letter of intent for the purchase of 3 million tons of LNG annually from Oman. Production is expected to come from non-associated gas discoveries in central Oman and 7 Tcf of proven gas reserves have been dedicated to this project by Oman government. A two train liquefaction plant to produce 6 million tons per year is expected to be built near Muscat.

✓ Korea has signed a memorandum of understanding with Yukon Pacific Corporation to take 2 million tons annually with a second 2 million tons option from the Alaskan TAGS (Trans-Alaska Gas System) pipeline and LNG export project. North Slope has 37 Tcf of proven natural gas reserves and TAGS will export 14 million tons of LNG annually from liquefaction plant located at Anderson Bay, near Valdez. Yukon Pacific announced the estimated project cost for the entire facility at \$13.4 billion (US/1991). The TAGS project has received major necessary statutory and regulatory approvals from US federal government. This project, however, could be realized when joint purchasing of the produced LNG is agreed and committed by LNG buyers of Asian countries such as Korea, Japan and others.

Indonesia (Natuna) and Malaysia have potential gas reserves to support grassroots LNG plants. These reserves, however, may be used to feed existing LNG export facilities. Meanwhile, the third Malaysian LNG project is expected to start up in the late 1990s. Deliveries to Korea are projected to begin soon after 2000.

Australia's Gorgon project is expected on stream by 2005, serving Korea. A volume of 2.5 million tons annually to Korea may be anticipated by 2010. There is another small gas reserves sufficient to support a 2 million tons per year LNG project which is located in offshore areas of Bonaparte Gulf. This project will be realized beyond 2015.

Interest in Papua New Guinea offshore resources has revived recently. Considerable work is needed to develop the fiscal and organizational regime needed to support an LNG project within the country. This project is assumed to come on-line by 2010.

Recent indications of substantial gas reserves offshore of Sakhalin Island could be at least partially used to supply a new grassroots LNG project, which could be exported to Korea and Japan. The LNG export from Sakhalin II project are assumed to begin 2005.

Korea has established a Korea-Russia consortium in order to carry out a preliminary feasibility study on developing gas fields in Yakutsk, East Siberia, with the aim to supply natural gas to Korea by trans-continental pipeline. As an alternative way of supply, the study may include a scheme that the produced gas could be delivered to liquefaction plant which will be assumed the location near Vladivostok harbour by 4,000 km pipeline. The proven natural gas reserves is 35 Tcf and the completion of this project is assumed beyond 2010.

Iran, with the second largest natural gas reserves in the world, will become another possible future LNG exporter in the Middle East, although Iran has made several exports deals by pipelines. Iran is carrying out a joint feasibility study with Gaz de France on the economical method of delivering natural gas to Europe, either pipeline or LNG. Iran has 730 Tcf of proved natural gas reserves.

5. Trans-Asian Natural Gas Pipeline Study

As previously explained, Korea is carrying out the preliminary feasibility study to develop Yakutsk gas field and import the natural gas by trans-continental pipeline or combination of pipeline and LNG ship transportation. Korea also reviews a scheme to transport the natural gas by means of pipeline passing through North-Korea as a part of so-called Trans-Asian Natural Gas Pipeline Network. This scheme is prepared as one of long-term security plans of natural gas supply to Korea for the coming century.

The "Trans-Asian Natural Gas Pipeline Network" has been studied by Japan for the purpose of increasing the use of undeveloped large natural gas reserves in the Asia-Pacific region including Siberian Russia and central Asia.

Besides the enormous project cost, there are many technical difficulties to be overcome including the politics of pipelines crossing several international borders. Thus it is important to make a consensus on the role of energy supply and demand between the countries in the region for the development of the Trans-Asian Natural Gas Pipeline Network. I think it is necessary to establish an international forum, in cooperation with all the countries in the region, in order to undertake the study of construction for the Trans-Asian Natural Gas Pipelines.

The development of the Trans-Asian Natural Gas Pipeline Network will promote the natural gas industry in the region, and will also play a important role in securing the natural gas supply for the countries currently importing LNG beyond 2010.

6. Conclusion

As long as current trends of energy market continue, Korea will make its effort to promote the use of natural gas as an alternative to oil and coal in the power generation, residential and commercial sectors, and as a clean energy to improve the environment. To this end, Korea keep on the construction works for expansion of LNG receiving terminals and nationwide pipelines, as well as building new facilities.

Energy security as it applies to natural gas is being taken increasingly seriously, because natural gas supply to Korea currently depends on imported LNG under long-term and short-term contracts from LNG projects in three ASEAN countries. Thus, Korea needs making efforts to diversify the sources of natural gas importation.

In view of long-term stable supply of natural gas, Korea will promote new export LNG projects dedicated to Korea. The Korean private enterprises, who newly enter into LNG business and become the potential importers, will also take the leading role in developing new LNG project. Furthermore, Korea is now making a great efforts into the study of preliminary feasibility on the development of gas field in Yakutsk and trans-continental gas pipelines lead to Korea.

In realizing these projects, Korea needs to collaborate with the countries in the Asia-Pacific and Middle East regions, especially Japan, in all phases of the project development in order to take maximum advantage of synergy and to solve any technical difficulties, political and financing matters.

While trying not to be over optimistic, the author believes that the Korea gas industry holds the capability to meet the challenge, and go forward by coping with the effective market.

TAGS Competition:

**Projects, Start-up
Dates, Annual Volumes**



TAGS Competition is Other Undeveloped Gas Fields in:

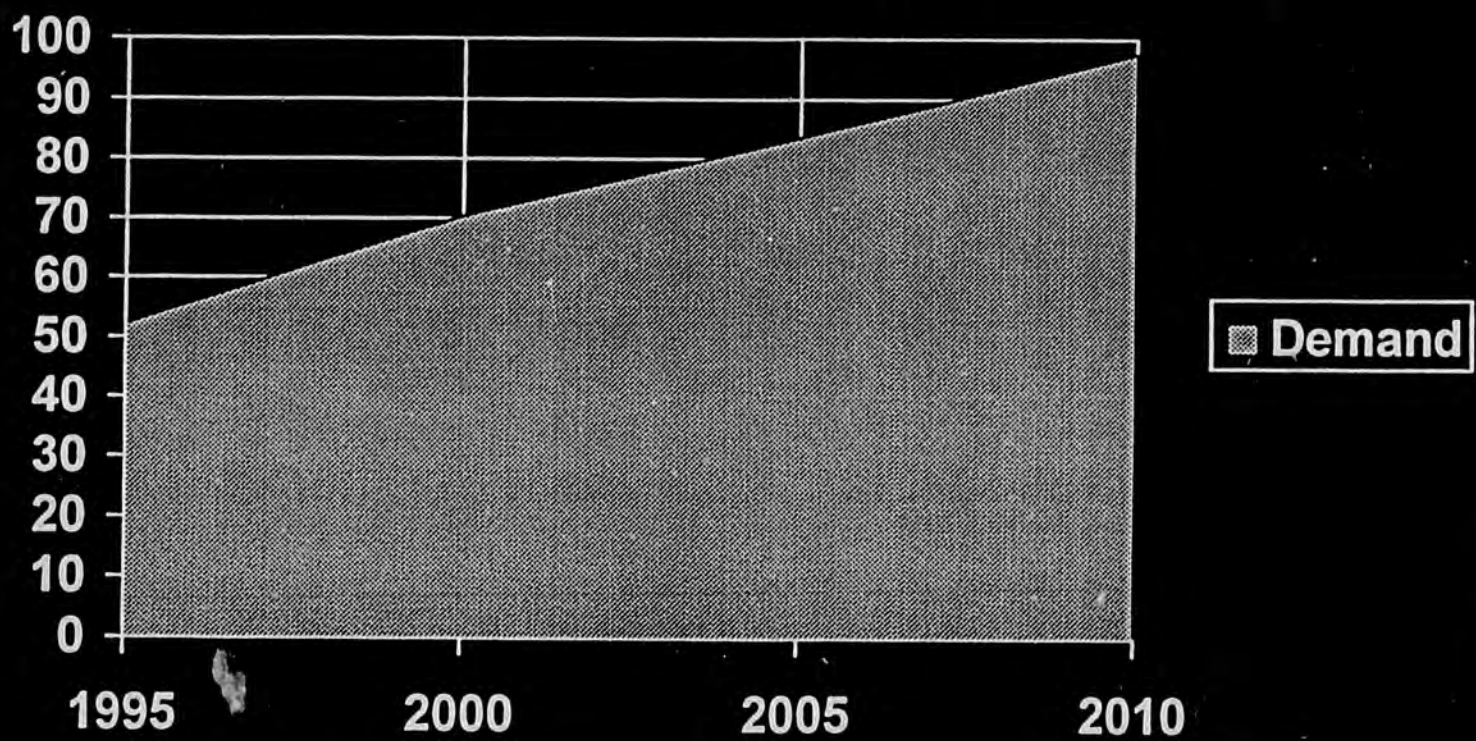
	<u>Start-up Date</u>	<u>Annual Volume</u>
▲ Qatar (Qatargas & Rasgas) - Mobil	2003	6-10 MMTA
▲ Indonesia (Natuna Island) - Exxon	2004	15 MMTA
▲ Sakhalin (Russia) - Exxon x2, Marathon/Shell	2004	6 MMTA
▲ Yemen - Exxon	??	2 MMTA
▲ Papua New Guinea - BP	??	2 MMTA
▲ Oman - Shell	2005	6 MMTA
▲ Australia - Shell, BP	2003	16 MMTA

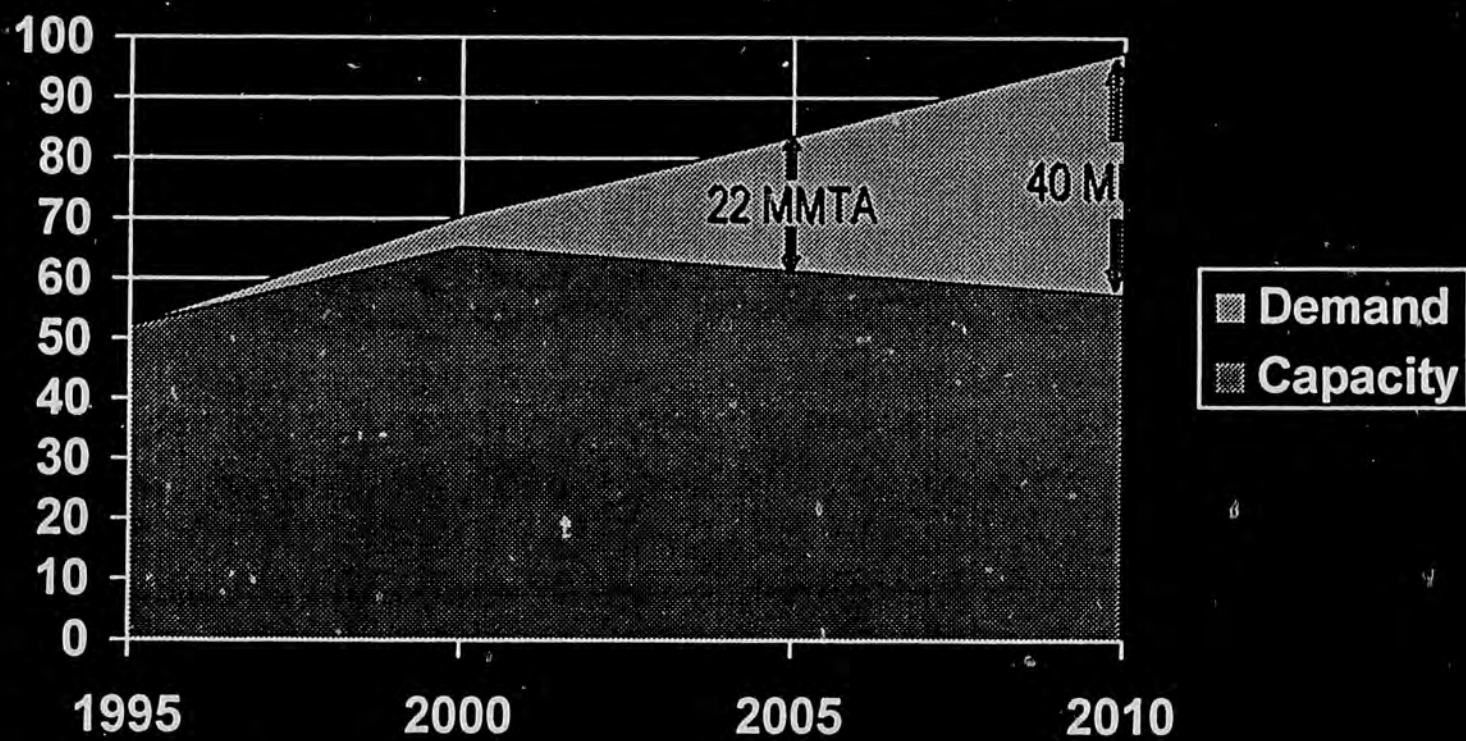
Each host country (together with the private gas producers shown above) is actively promoting its project as the next post-2000 LNG supplier to Asia.

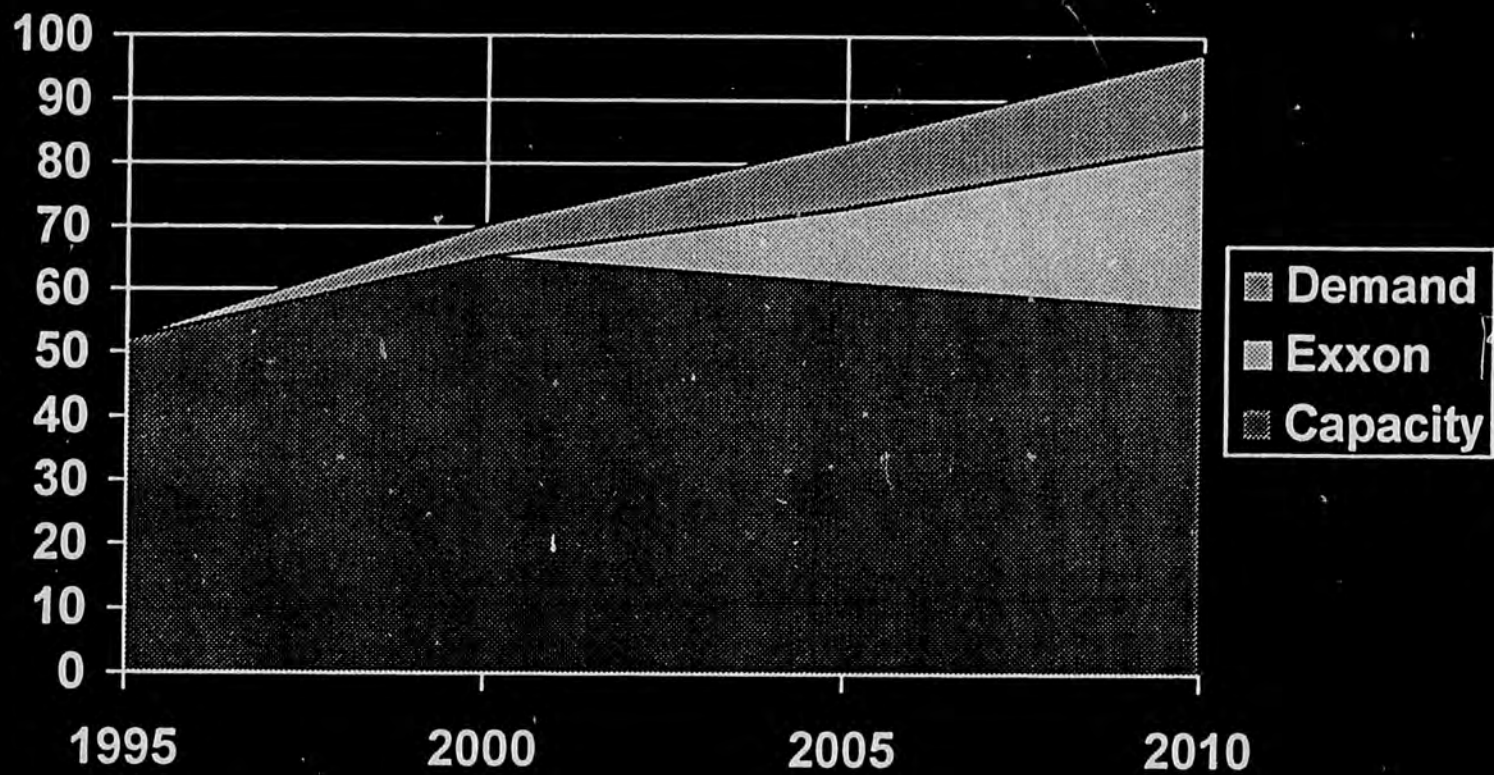
The Post-2000 Demand Window:

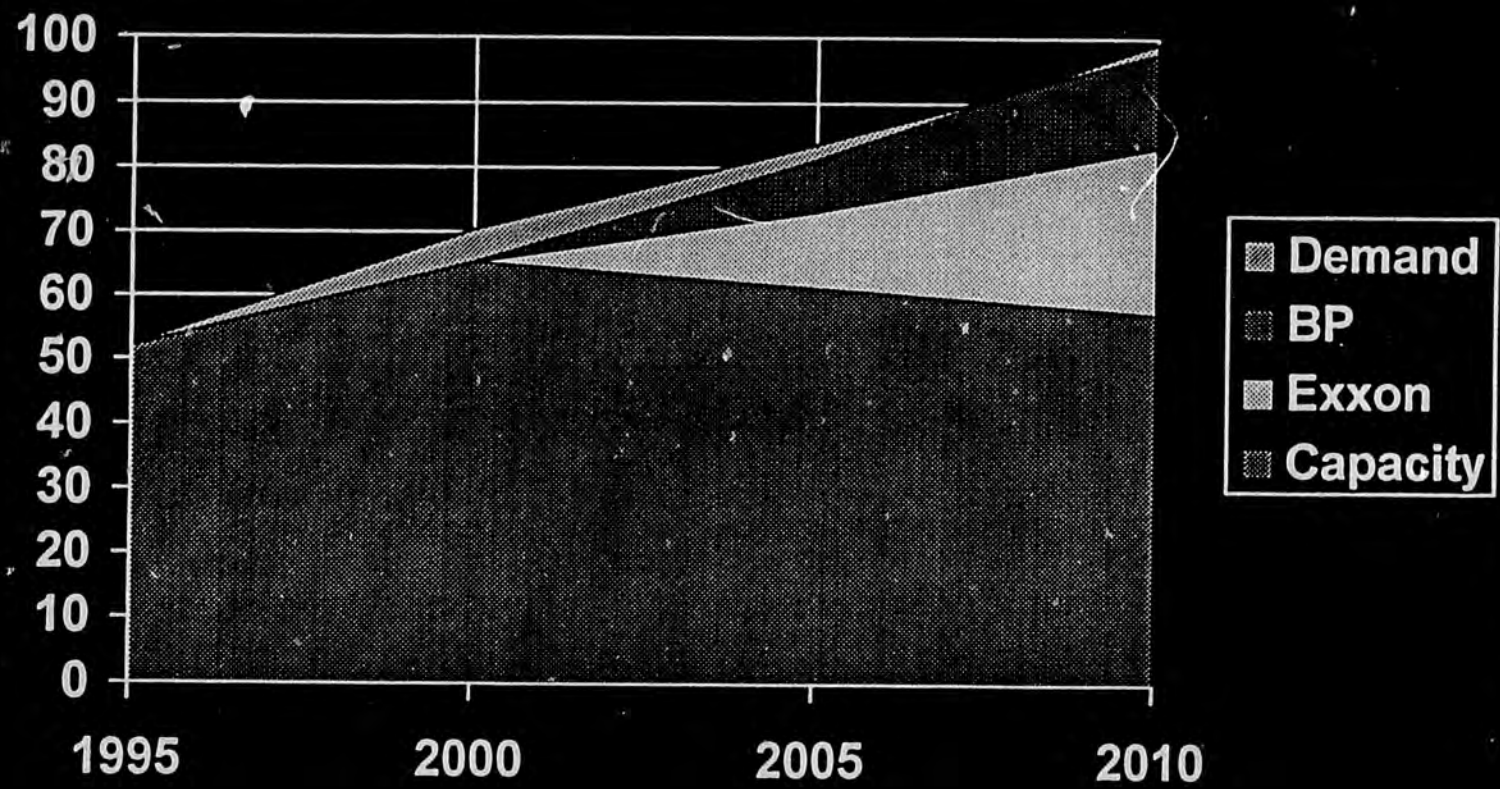
The Effects of
Competition on an
Alaskan Project



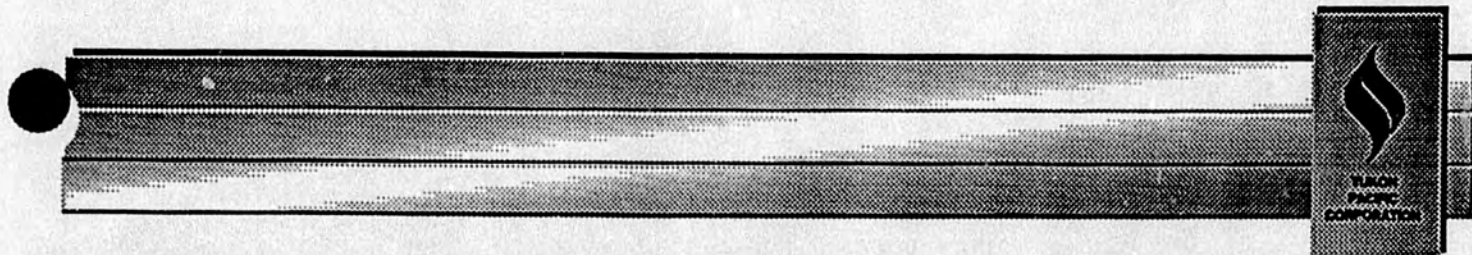




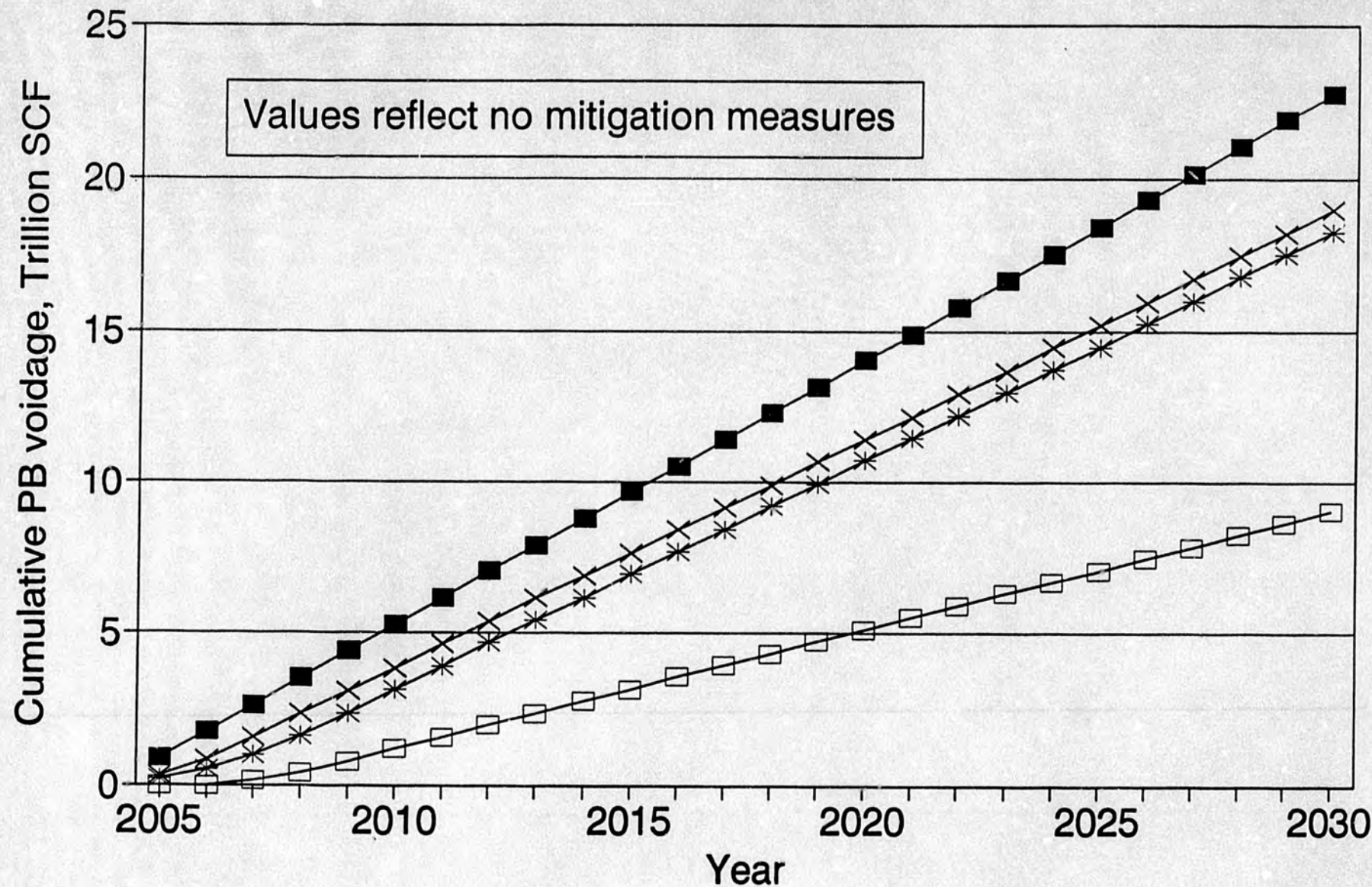




Oil Loss vs. Gas Sales



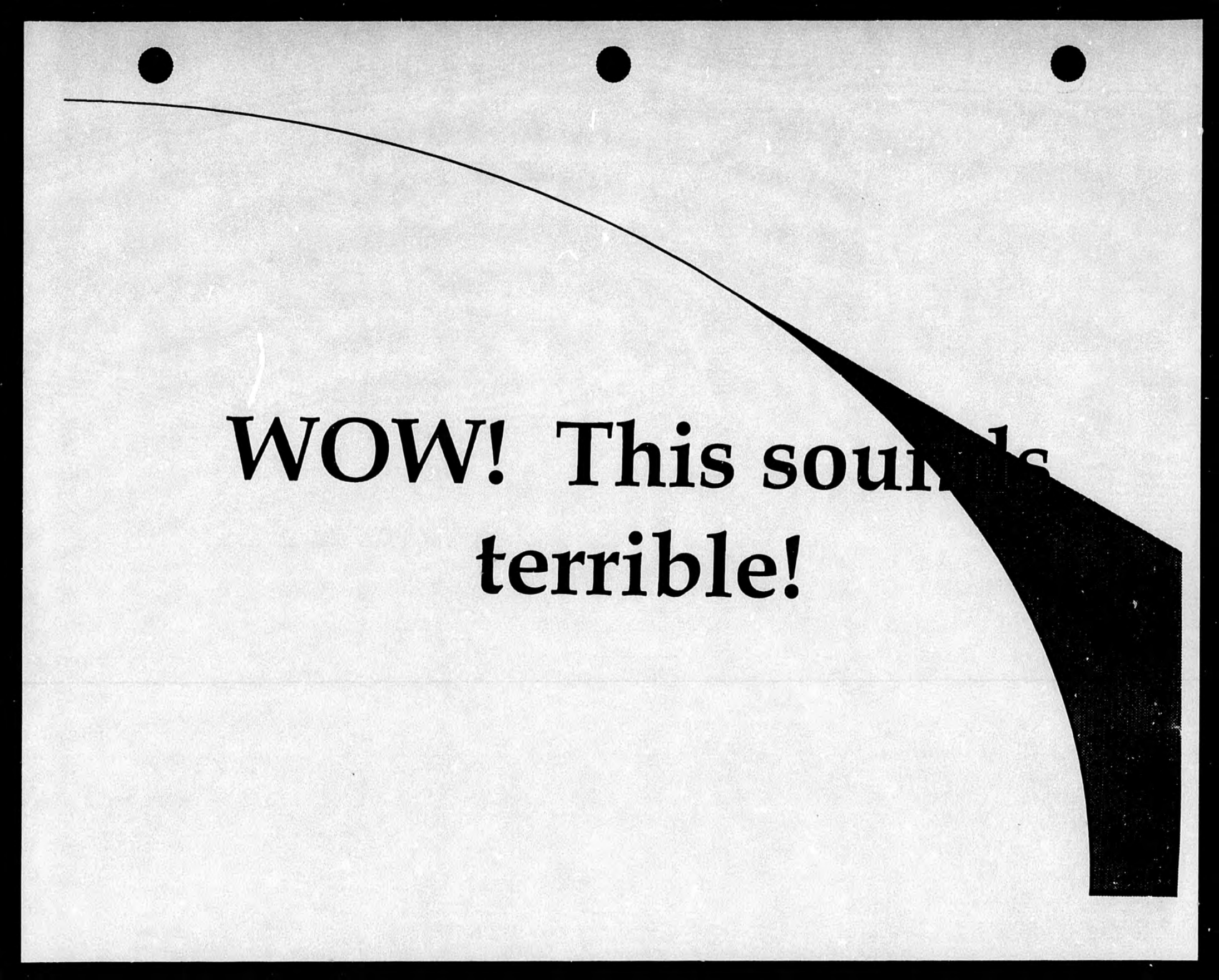
PBU Oil Pool, Cumulative Reservoir Voidage Due To MGS Scenarios



■ PBU 400 MMB * TAGS 5 yr ramp □ w/ Pt. Thomson x TAGS 3 yr ramp

Risks?

Oil Loss: “potential
400,000,000 barrels lost
from PBU if gas sales
begin in 2005.”



**WOW! This sounds
terrible!**

Not Really.

Gas revenues *more* than offset
any "potential" oil loss...which
is "uncertain" at best.

Oil Loss?

Key Questions:

- ▲ What is the schedule of loss-i.e. *when does it occur?*
- ▲ What gas "ramp up" rate is used?
- ▲ What mitigation can be used to minimize on oil?
- ▲ When does TAPS shut down?
- ▲ What are the PBU economics supporting viability through 2030 without gas sales?
- ▲ Can Point Thomson gas solve the PBU problems?

Oil Loss?

Extremely "Uncertain":

"...Commissioners, in any forecasting process when you go out and look at the future, as one steps out in time uncertainty grows, asymptotically -- or exponentially, I should say.

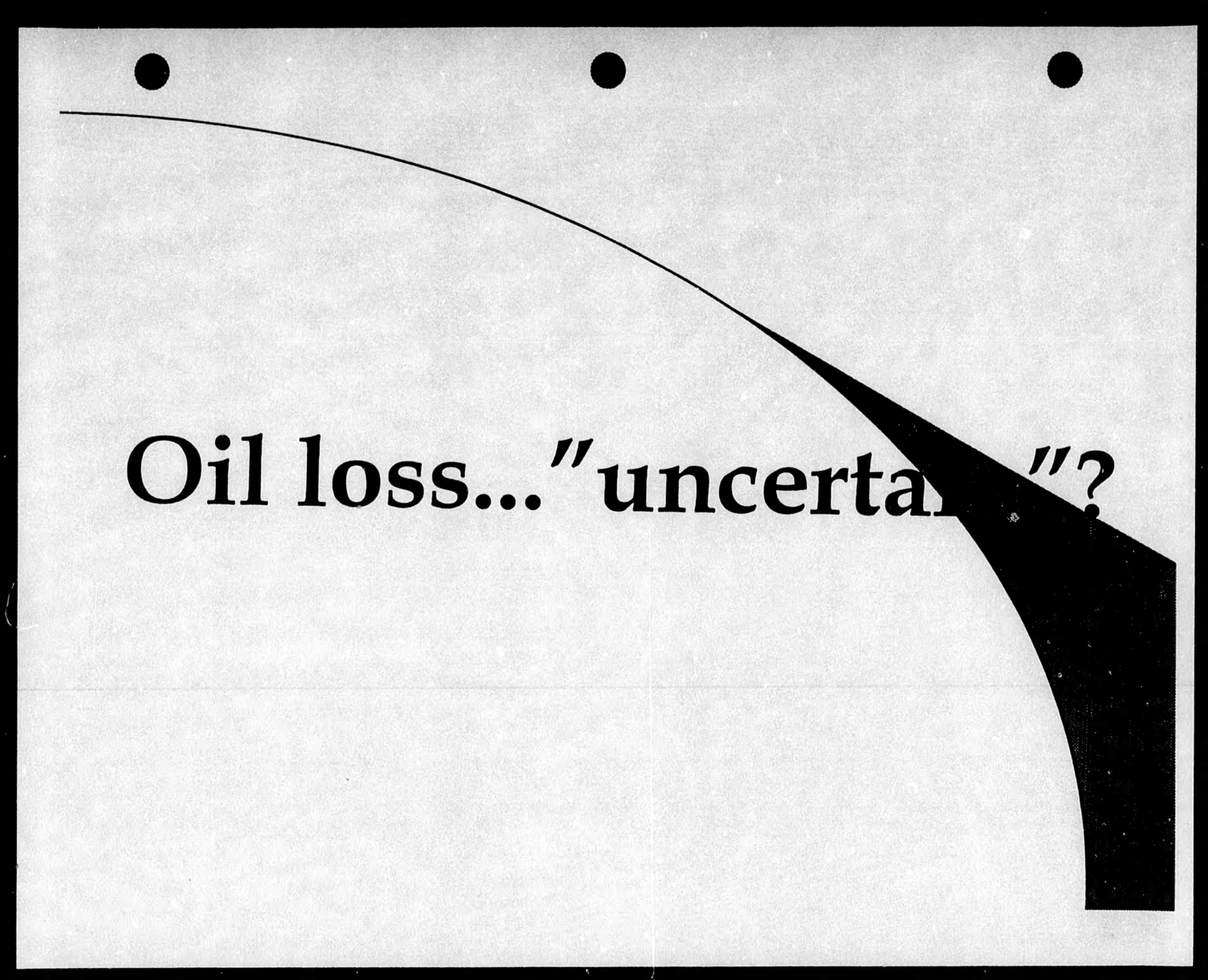
Do we have a forecast for the year 2020?

Yes. Do we have a lot of faith in it?

There's a lot of uncertainty there...."

PBU's 1991
Legislative
Testimony

Oil loss at PBU is *highly*
"uncertain" but the loss of both
Point Thomson *and* Prudhoe
gas revenues without a gas project
is *absolutely certain!*



Oil loss..."uncertain"?

(48)

Gas revenues are certain!

- ▲ Gas revenues are set by contract for 25 years (i.e., no risk).
- ▲ BP says, "Money flows to the areas offering the greatest returns for lowest risks."

We agree!
Gas sales = lowest risk...
Hands Down

What do you get *without* gas sales?

- ▲ "Uncertain" oil recovery?

What do you get *with* gas sales?

- ▲ Certain revenues for 25 years from PBU gas sales
- ▲ Probable revenues from 5-7TCF of gas and 300 MMB at Point Thomson
- ▲ Non-PBU revenues (taxes...)
- ▲ Stimulation of State economy (jobs!)

ARCO/BRITISH PETROLEUM PRESS BRIEFING - JULY 19, 1995

Ken Thompson (KT):

Thank you for coming this morning. North Slope oil and gas producers Arco, BP and Exxon have completed a study of options for transporting North Slope gas to Pacific Rim markets and have briefed Governor Tony Knowles and Alaska's Congressional delegation, Senators Ted Stevens and Frank Murkowski and Representative Don Young on the results of their study. Good progress has been made on project definition and cost. While the study has identified cost savings, none of the options under consideration is currently commercially viable. The companies noted that commercializing North Slope Gas will be one of the most expensive and complex business undertakings in history. Significant uncertainty remains in the areas of fiscal and regulatory conditions, market timing, product pricing and project cost. A project of this size, cost and complexity will require the involvement and cooperation of many parties, including the state and federal governments. Arco, BP and Exxon are committed to continuing to seek ways to make North Slope gas commercially competitive and will set up discussions with the state and federal governments on how we can work together to establish certainty for an appropriate tax and regulatory framework for a commercial project.

And we would be happy to take any questions that you may have.

- 1) Could you discuss the route options? One, have you decided on one, if not, are you considering more than one? Or may be you could just talk about the route options.

John Morgan(JM):

Yes, the reason we have looked at alternative routes here, they are both part of our effort here to try to get the cost of this project to be lower. The route that most people think of is the obvious one which is down alongside the existing TAPS line it essentially is a long pipeline and very expensive. What that does is drive you to have a very big project, which then introduces greater difficulty in terms of marketing the gas - you need to sell it quickly to get a fast build up to make the economics work. As a result of that we began to look whether there would be alternative pipeline options which would be cheaper and those are the western route options, one of them coming out close to Wainwright and the other one close to Kivalina. We've done initial scoping on those routes and at the moment think they are both feasible, both in terms of pipeline logistics and the marine conditions at ports there, so that's the initial process and we have now to decide whether to examine those routes in more detail with more specific engineering and I'm sure that will be one of the things that is part of our conversation with the Governor and his team and the state as we move forward. So there is no decision at this point on the line. The route that is undoubtedly best worked is the route that runs along side TAPS and the decision is whether to work the other routes in more detail.

KT:

I'd like to mention adding to that, that as we studied the current LNG projects that are already existing we found that Alaska North Slope gas is not competitive compared to those. One thing that we have that the others do not have is an 800 mile pipeline or one of the shorter lines to the west. Most of those projects are pretty close to the coast in areas where they can be loaded on tankers. That's an incremental cost that is pretty substantial and does add cents per million

market before new greenfields. So that's the time frame you wanted, a sort of estimate I would put it in the, the potential, the first potential would be in that time-period, probably towards the back end of that 2005 to 2010 period.

- 7) Does that also jive with your plans as the Prudhoe curve kicks in and the oil supply depletes on the slope makes the gas available?

KT:

When you look at that time frame there, it does and also we find that it's minimal oil loss and it does not play into the decision whatsoever, in fact, we keep coming back to moving forward on this project. We need three things; fiscal certainty, further cost reductions and confirming the market. And to describe a little bit more about the market that John was mentioning - we've looked at a lot of supply and demand forecasts for LNG now for several years and we've worked internally in a lot of detail, we've also worked with external consultants who have an objective view of that too and here's what we're seeing is we see that existing projects and those currently under construction today should be able to supply the market way past 2000 and those same projects do have potential expansion, and those expansions and construction would be able to be far less and more competitive than Alaska North Slope Gas. Those potential expansions would cover all of the supply through and past 2005. So we have confirmed that past 2005 or 2010 is an area that we are looking at in more detail and we will be visiting the market directly this fall. Arco, BP and Exxon will be jointly visiting Japan, Korea and Taiwan to further test their views and to talk to them about the progress we have made and about those next steps forward. And those next steps forward will be working with the state and federal government for fiscal certainty, looking for further cost reductions and in their view also confirming the market that we see in the post 2005 to 2010 or so.

- 8) How much natural gas will be utilized to pump back into the fields and still sell, how much would you sell, how much would you need to pump back into the North Slope to keep pushing oil?

KT:

The question still comes back...that's not the key issue about LNG. The key issue is fiscal certainty, market and cost, that's when LNG will become competitive and it's not the amount of oil we see in this time frame, it's minimal oil loss, so that has not driven the decisions on this. What's driven the decisions are those three things I mentioned.

JM:

We don't believe there's an issue of any significance. If we can define this project in that time scale we're talking about, the interrelationship with oil production is unlikely to be of significance.

- 9) So it's not one or the other is what your saying, because it was my understanding earlier about two (2) years ago that you'd have to give up something to produce LNG, we'd have to give up our oil. Your saying that's not the case.

KT:

I might mention a few years ago there was discussion by some that there would be LNG sales by 1997 or 1998. If that were to have been the case, there would be very, very substantial oil loss which we feel would not have been good for the producers nor for the state nor the people of Alaska. Looking at a time frame post 2005, that oil loss, if any would be minimal and it switches more to the fundamentals of the LNG business which we're trying to make happen and resolve those three issues.

- 10) Was there a change in technology then because it was my understanding that you use natural gas to pump more oil out of the ground, so what's changed?

KT:

It's not an issue of technology, it's an issue of just depletion of the remaining oil reserves in that time frame there, plus looking at the LNG business in that timeframe.

- 11) a) I have a two part question: Is it fair to say that if you were to choose the western route that this would be a smaller project in terms of tons of LNG per year as verses, say, the TAGS proposal? And then I have a second question, too.

JM:

Well, I think as I was suggesting earlier, one of the key reasons to look at the western routes is to try and reduce the cost of the overall project. Now either that's partly reducing the cost of the pipeline because it's a shorter line because the size of the southern route line drives the cost of the LNG price that you need in order to get a profit So if you can reduce the cost of the pipeline there is a serious possibility that you may be able to use the cost of the therefore make the market problem of having this very large wall of gas that you want to sell in the market at one time go way to some extent. We can't tell you at this point we are sure we would be able to do that that's why I think we have to now consider where we want to go the next step in engineering to look at studies on the western routes to see whether it really does offer that kind of potential.

- 11) b) So if I understand you correctly, I'm not quite sure you answered the question, if you were to go with the western route, either one of those two options, would you, I think TAGS is proposing up to 14 million tons per year, would your project be smaller than 14 million tons, would it be say half as much or are you looking at equally as large a project in terms of bringing LNG to?

JM:

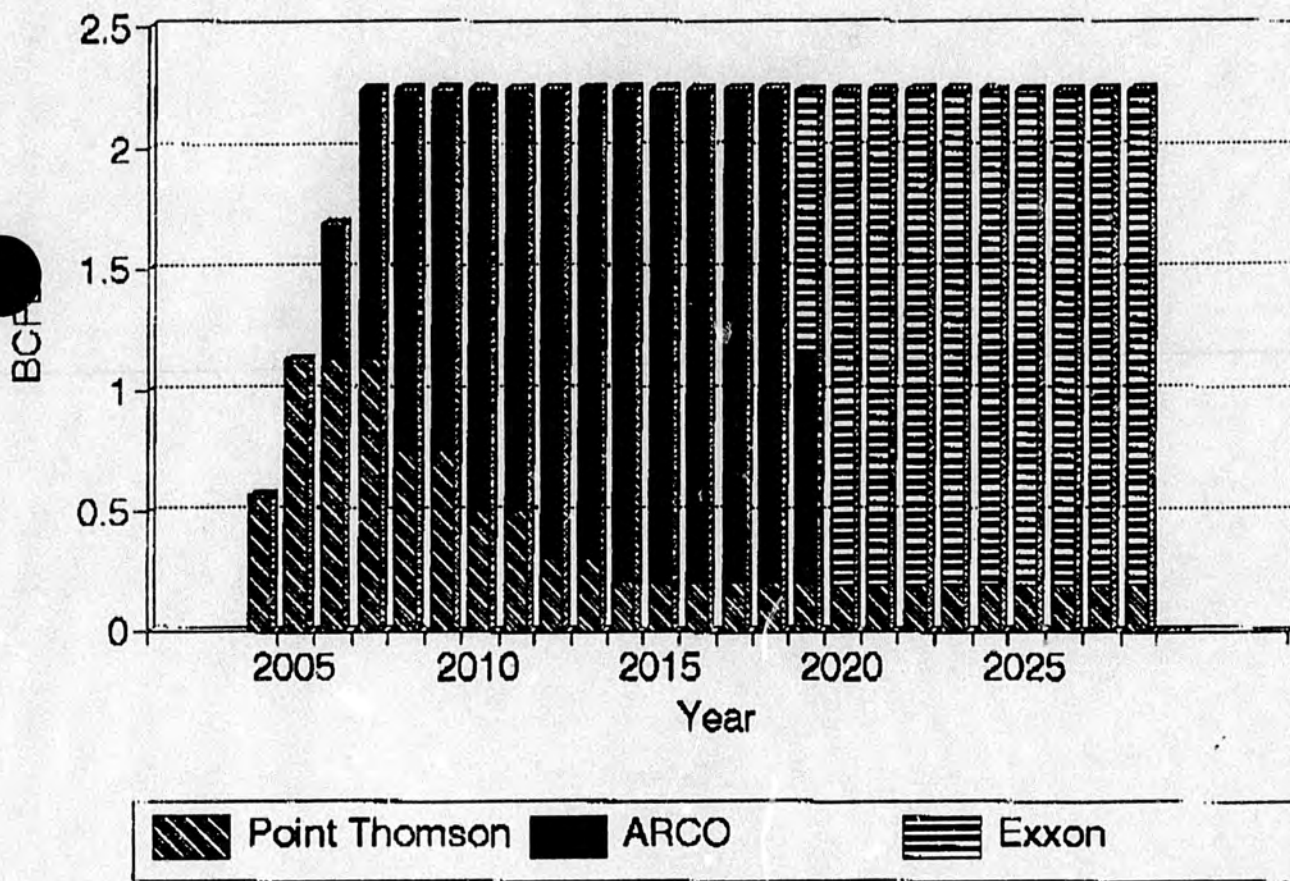
Try answering it this way...since one of the reasons we are looking at the western routes is to see if we can reduce the cost, it is likely that if conditions of going the western route that we had found a way of building a smaller project. I'm not going to tell you it's going to be half the size, I frankly don't know. But that is one of the reasons to examine that. So it is likely, the western route solution would be linked to a smaller scale project, and one that was more easy to make work from a financial and economic point of view than the southern route.

Possible North Slope Gas Supply Scenarios



Trans-Alaska Gas System

Supply by Field/Producer



Ruling issued on MI and NGL

ANCHORAGE—The Alaska Oil and Gas Conservation Commission (AOGCC) issued a decision August 9th following the Prudhoe Bay Unit Miscible Injectant (MI) Natural Gas Liquids (NGL) hearing that took place in May and June of this year. The AOGCC has ordered the Unit Operators to increase the blending of NGLs to the maximum volume that can be tendered to TAPS beginning

immediately through August 31, 1996.

The field operators, BPXA and ARCO, have begun to increase the rate of NGL Blending in compliance with the order.

The Central Gas Facility (CGF) in Prudhoe Bay, the largest facility of its kind in the world, processes approximately seven billion cubic feet of natural gas per day. From that gas, the CGF manufac-

tures Natural Gas Liquids (NGLs) for shipment down the trans Alaska pipeline with the crude oil stream as well as Miscible Injectant, which is used for Enhanced Oil Recovery (EOR) from the field.

The average volume of NGL that has been manufactured and blended so far this year is approximately 64,000 barrels per day. The CGF has also manufactured approxi-

mately 520 million cubic feet per day of miscible injectant.

The matter before the AOGCC arose because there is a trade off between the manufacture of NGL and miscible injectant. The manufacture of more NGL will result in reduced capacity to manufacture miscible injectant in the short term.

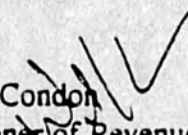
The Commission's most recent order requires that Unit Operators undertake

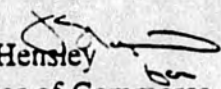
improvements to the CGF to increase the volume of miscible injectant that can be manufactured, while manufacturing the maximum volume of blendable NGL.

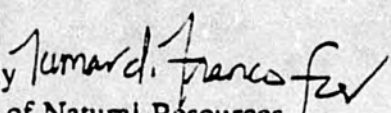
There were other extensive finds pertaining to the future development of Prudhoe Bay. BP Exploration and the other owners will be considering these rulings and deciding on their course of action.

Memorandum
State of Alaska

To: Tony Knowles
Governor

From: Wilson L. Condon 
Commissioner of Revenue

William L. Hensley 
Commissioner of Commerce
& Economic Development

John T. Shively 
Commissioner of Natural Resources

Bruce M. Botelho 
Attorney General

Date: January 22, 1996

Subject: Commercialization of North Slope Gas - What Should the State Be Doing?

I. INTRODUCTION.

What should the state government do to promote the project to pipe Alaska North Slope natural gas to tidewater, liquefy it, and tanker the liquefied natural gas (LNG) to customers in Japan, Taiwan and South Korea? The Departments of Revenue, Natural Resources, Commerce and Economic Development and Law have prepared this briefing paper to address this question. The three major North Slope oil producers (Arco, BP, and Exxon), and the Yukon Pacific Corporation (YPC), were consulted in the preparation of this paper.

Alaska North Slope proven natural gas reserves are very large: in the range of 35 trillion cubic feet (tcf). They include Prudhoe Bay at 26 tcf, Point Thomson at 3 to 5 tcf, and Kuparuk, Lisburne, and Endicott, together at 2 to 6 tcf. The amount of energy in these gas reserves is

equivalent to 6 billion barrels of oil - the amount of current remaining developed oil reserves on the North Slope.

Since 1970 various interested firms have continuously studied the possibility of commercializing these large North Slope gas reserves. First came the Gas Arctic Project of the early 1970's (a pipeline through the Arctic Refuge and up the McKenzie River to the mid-continent). Then followed the El Paso project of the mid-1970's (a pipeline to a Prince William Sound liquefaction plant and LNG deliveries to California). Next came the Alcan Project of the late 1970's and early 1980's (a pipeline to Fairbanks and then down the Alcan Highway to the mid-continent - some of the southern Canadian portions of this project were actually constructed). This was followed by the proposed Trans Alaska Gas System project (TAGS) in the early 1980's that has now evolved into the project proposed by YPC today (a pipeline to a Prince William Sound liquefaction plant and LNG deliveries to the Far East). During the 1980's and 1990's, while the TAGS sponsors were promoting their project to deliver Alaska LNG to the Far East, some of the Prudhoe Bay producers continued to study projects to deliver North Slope gas to the North American mid-continent. Recently, however, the major North Slope producers have clearly shifted the focus of their ANS gas commercialization efforts to the Far East.

Here's where things sit today. The producers recently released their findings on a proposed project that would market Alaska LNG in the Far East. Representatives of the major North Slope producers then visited potential customers in Far East markets. Representatives of YPC have just completed another of their many Far East marketing trips. Further, Phillips, a relatively minor

Prudhoe Bay producer with significant interests in a yet undeveloped North Slope gas and condensate field, Point Thomson, has recently proposed to commence the project by marketing gas from that field to expedite commencement of a North Slope to Far East LNG project.

At today's energy prices and projected construction costs, the economic feasibility of the proposed Alaska LNG project appears doubtful. Minimally, either increases in gas prices or decreases in projected construction costs must occur to make the project economically viable. If constructed, the potential revenues to the state over the life of the project under the current tax and royalty fiscal regime will be much smaller - by at least a factor of 10 - than the revenues the state will receive from North Slope oil developments over the life of those projects. However, as North Slope oil production continues its decline, proposals to commercialize the vast natural gas reserves on the North Slope inevitably draw increased attention. North Slope gas would make some contribution to state revenues, thereby somewhat offsetting the revenue loss of declining oil production. Further, many environmentalists contend that developing North Slope gas is much more environmentally responsible than further North Slope oil development.

We recommend the state address several issues now to enhance the chances that interested firms - including the North Slope lessees - will construct a North Slope gas project for three reasons. First, new marketing opportunities may soon open. Second, long lead times will be required to construct the project. Third, the competition from other countries to capture the gas marketing opportunities in the Far East are and will continue to be formidable.

We recommend you designate a working team from the pertinent executive departments to accomplish the following:

1. Determine if any modifications to the terms of the state's fiscal regime applicable to ANS gas production would significantly enhance the economic feasibility of the proposed project;
2. Carefully evaluate the costs and benefits of the potential modifications to the state's fiscal regime that would significantly enhance the economic feasibility of the proposed project;
3. Determine if there are any modifications to the federal tax structure pertaining to this proposed project the state could responsibly promote that would significantly enhance the economic feasibility of the proposed project;
4. Determine and pursue actions to facilitate federal action on permits and licenses needed for the proposed project;
5. Determine what actions the state could take with respect to its options to take its royalty share of North Slope gas production in-kind that would promote the construction of the project;

6. Determine what actions the state could take with respect to its royalty-in-kind options to maximize state benefits from the proposed project;
7. Determine and pursue actions to assist in marketing ANS gas to would-be customers in the Far East;
8. Assist in interesting would-be investors, particularly those from the Far East destination market countries, to commit to the project;
9. Evaluate whether the state should or should not invest in the proposed project;
10. Work with the Point Thomson working interest owners who have apparently expressed an interest in providing large volumes of gas for the proposed project well before 2010, the date the Prudhoe Bay producers have indicated as "most likely" for the commencement of gas deliveries from the Prudhoe Bay reservoir;
11. Work with the Prudhoe Bay producers to better understand the effect that large scale gas sales will have on future oil production from the Prudhoe Bay reservoir;
12. Evaluate the environmental considerations pertinent to the differing routes and terminal locations for the proposed pipeline project;

13. Work with the producers and YPC to ascertain what other steps the state might responsibly take to facilitate this project; and
14. Determine whether there are any other feasible commercialization options, including:
 - Marketing the gas in the Lower 48;
 - Converting gas on the North Slope to hydrocarbons that are liquid and can be transported in the TAPS pipeline; or
 - Generating electricity on the North Slope and using high efficiency transmission lines to move the electricity to market.

II. FACTORS INFLUENCING THE COMMERCIALIZATION OF NORTH SLOPE GAS.

Five major factors currently determine the feasibility of the large scale commercialization of North Slope gas. They are:

- The cost of developing the gas delivery system relative to expected gas prices
- The demand for the gas in the Far East markets and competition among potential supplies of LNG
- The pipeline economic disadvantage in competing for a place in the market
- How the sale of the gas would affect Prudhoe Bay liquid production
- The availability of an alternative North Slope gas supply prior to full scale Prudhoe Bay

gas availability

1. Cost Relative to Expected Gas Prices

Developing the transportation system to move North Slope gas to the Far East market will be very expensive. Here is what will be needed:

- Gas conditioning plant (approximately 10% of total cost)
- Pipeline to tidewater (approximately 40% of total cost for a Valdez route)
- LNG plant and marine terminal (approximately 25% of total cost)
- A fleet of LNG tankers (approximately 25% of total cost)

Both the producers and YPC currently estimate that the project would cost \$15 billion. There may be opportunities to reduce the cost by \$3 billion through infrastructure sharing, more efficient pipeline construction methods, larger LNG liquefaction trains, and a more economic ship design. The producers claim it would cost \$100 million for a detailed engineering study to assess whether significant savings are now possible. The producers differ in their assessments of the likelihood that they will soon actually undertake such a study.

Infrastructure sharing includes:

- Use of the Prudhoe Bay compression facilities, camps and power generation for the gas conditioning plant

- Conversion of some of the TAPS pump stations to compressor stations, and using the oil pipeline workpads and state highways for the pipeline
- Use of the Valdez marine terminal facilities, civil work and loading berth for the LNG plant¹

Pipeline construction advances include Arctic application of state-of-the-art ditching machines, use of high strength pipe, and pipe laying rates that are much faster than those used at the time TAPS was constructed.

Larger LNG liquefaction trains² (larger than currently available) can reduce per unit liquefaction costs.

In addition, the producers have been analyzing additional savings from pipeline routes to the northwestern Alaska coast at either Wainwright or Kivalina. These routes avoid mountains and are less than half the distance to Valdez. They would, however, require ice-breaking LNG tankers, which have never operated in pack ice before. By reducing the high fixed cost of the pipeline, the western route would afford the project the opportunity to commence operations in smaller stages and thus enhance the start-up economics of the proposed project. The staging advantage is discussed in more detail in Section II(3) below. The producers are still studying the

¹ There is some question as to whether an LNG plant located very close to the oil facilities might violate exclusion zone requirements for LNG siting established by the U.S. Department of Transportation.

² A train is an individual liquefaction and shipping unit.

relative advantages and disadvantages of the western routes.

On an overall project basis, the minimum cost efficient size of the project appears to require a sale and delivery of 2 billion cubic feet (bcf) per day. This results in annual deliveries of 14 million metric tons of LNG - the unit of measure used in the Far East LNG markets.³ The project requires a ten year lead time to achieve full operation; five years for construction, and five years to ramp-up to full production.

LNG is sold in the Far East markets on a per million British Thermal Unit (mmbtu) basis.

Generally, pure natural gas - methane - has an energy content of about 1,000 btu per cubic foot; that is one million btus per thousand cubic feet (mcf). However, both the North Slope producers and YPC maintain that the North Slope gas would be "spiked" with ethane, propane, and butane to increase the energy value per unit of volume and thus to enhance its value.⁴ The producers estimate the gas used for the proposed project would be spiked to 1,170 btu per cubic foot for the first ten years, and 1,100 thereafter. In the economic analysis we have done for this paper, we have assumed an average energy content of 1,150 btu per cubic foot of natural gas for the duration of the project. This "spiking" enhances the value of the gas by 15%.

³ To put the likely size of a gas line project in context with the current North Slope oil production operations, a two billion cubic feet per day gas line would carry the energy equivalent of about 350,000 barrels per day of oil.

⁴ Ethane, propane and butane are more complex hydrocarbons often classified as "NGL's" at ordinary temperature and pressure. These substances are, however, gases. They have significantly higher energy content per cubic foot than methane.

If this project is constructed, how much will it cost to ship ANS gas to the Far East? If the project (1) costs \$15 billion (both the producers' and YPC's current estimate), (2) operates for 25 years with daily throughput of 2 bcf. and (3) earns a 4% after-tax real rate of return (11.4% nominal), then it will cost \$5/mmbtu to ship the ANS gas from the North Slope to the Far East.⁵ This cost includes a 50 cent/mcf operating cost and a 30 cent/mcf cost pertinent to the state's 20 mill oil and gas property tax.⁶ LNG today is selling for about \$3.50/mmbtu in the Far East, 30% lower than the \$5.00/mmbtu projected cost for transporting gas from the North Slope of Alaska to that market. At this price, these economic projections yield a negative wellhead value of \$1.50/mmbtu for the project. Put otherwise, based on these projected costs, a threshold gas price of \$5.00/mmbtu in the Far East markets is necessary to yield a zero wellhead value at the North Slope. It is obvious that if these costs are correct, then higher wellhead values would be required to induce investors to construct this project.

If the gas price remains at \$3.50/mcf in the destination market, how would it be possible to raise the wellhead value? By reducing the capital costs for the project by one third either by significantly lowering the rate of return on the project or by greatly reducing construction costs or

⁵ This assumes 75% debt, 25% equity, with a nominal rate of return of 12.9% on the equity and a rate for the debt two percentage points below the return on equity. YPC has suggested that 75-25 is a likely debt/equity ratio for the project. We have assumed equity and debt rates of return that may not accurately reflect those that would be obtained for financing the project. We believe, however, that a real after-tax rate of return of about 4% for the project is the lowest return investors would accept. See Appendix A for a more detailed discussion of the economic analysis pertinent to this project.

⁶ This 50 cent/mcf operating cost has been suggested as the likely operating cost by both the producers and YPC.

both.⁷

What about the LNG price in the Far East? For this proposed project to be economically feasible, that price would have to increase to at least \$5.00/mmbtu if the project and capital costs cannot be significantly reduced.

LNG in Japan currently commands a 15% premium over crude oil on an energy equivalent basis.⁸

This premium arises from several factors:

- Gas burns much more cleanly than fuels derived from crude oil.
- Gas powered units such as gas turbine electric generators are more efficient and require lower capital costs than their oil powered cousins.
- Recognizing the high costs of LNG projects, parties in the Far East markets have negotiated premiums for LNG with respect to crude oil at low oil prices, and corresponding discounts at high oil prices.

It follows that a \$5/mmbtu LNG price is equivalent to a price of \$25 per barrel (bbl) for crude oil.

⁷ Pursuant to the settlement agreement governing the TAPS tariff, the TAPS oil pipeline has been permitted to earn a 6.4% after-tax real rate of return (15% nominal). The gas pipeline should be less risky than TAPS. A strong argument can be made that a 4% after-tax real rate of return will be required for this project. See Appendix A for a more detailed discussion.

⁸ Currently crude oil prices in Japan are between \$17 and \$18 per barrel. There are 5.8 times as many btus in a barrel of crude oil as an mcf of gas. Thus the following equation -- $5.8 \times 3.5/17.5 = 1.16$ -- tells you that a btu of energy derived from LNG selling for \$3.50/mmbtu costs 16% more than a btu of energy derived from crude oil selling for \$17.50/bbl.

In other words, given the current relationship between oil prices and gas prices, oil prices would have to be \$25/bbl in order for North Slope gas to provide a 4 1% real rate of return on the proposed transportation investment and leave a zero North Slope wellhead value. Currently crude oil sells for about \$17-18/bbl in Japan. If LNG did not command a premium over crude oil, the equivalent oil price in the Far East would have to be \$29/bbl.

Appendix A sets forth a more detailed discussion of the economics of the proposed ANS LNG project.

2. Far East Demand for LNG and Competition Among Potential Suppliers.

Current LNG consumption in the Far East is about 55 million metric tons per year (mmt)⁹ LNG consumption has been increasing at 6% per year since 1980, and is expected to grow between 5% and 10% annually through 2010. However, exponential growth cannot continue in this market indefinitely. Therefore, we have used a 6% annual growth rate for LNG demand in the Far East for planning with respect to this proposed project. Six percent annual growth would result in LNG consumption in the Far East markets of about 100 mmt in 2005 and 130 mmt in 2010.

There is no unsatisfied demand in the Far East LNG markets before the year 2000. Contracts sufficient to fill all the anticipated increases in the Far East demand through the end of this decade are already in place.

⁹ The proposed North Slope to Far East gas transportation project operating at 2 bcf per day would supply 14 mmt - about 25% of the current supply. The 55 million tons of LNG consumed each year in Far East markets is the daily energy use equivalent of about a million and a half barrels of oil per day - about the volume that currently flows through TAPS.

The LNG market opportunities are significantly different than the market opportunities for crude oil. There are few LNG buyers. Because of the large up-front investments required for an LNG project, and to reduce risk, long term contracts must be in place before the producers, the buyers or YPC would commence construction of the ANS gas transportation project.

The competition for selling LNG to the Far East is considerable. The following table shows, by country, existing supplies.

CURRENT SUPPLY TO FAR EAST LNG MARKET	
Location	Gas Supply (mmty)
<i>Alaska (Cook Inlet)</i>	1
<i>Abu Dhabi</i>	5
<i>Brunei</i>	7
<i>Indonesia</i>	27
<i>Australia</i>	7
<i>Malaysia</i>	8
Total	55

Capacity to supply an additional 8 mmty from Malaysia and 6 mmty from Qatar is currently under construction. Relatively low cost expansion of existing LNG facilities in Australia, Indonesia, and Malaysia of 5 mmty each (a total of 15 mmty) are under serious consideration.

The following table summarizes the existing supplies, supplies currently under construction, and available low cost expansion opportunities at existing LNG plants:

CURRENT AND NEAR TERM LNG SUPPLIES TO FAR EAST MARKET	
Source	Gas Supply (mmt)
Existing Supplies	55
New Plants Under Construction	14
Low Cost Expansion Opportunities Available	15
Total	84

Including the North Slope, new grass roots projects could add the amounts reflected in the following table.

LARGE NEW LNG PROJECTS PROPOSED TO SUPPLY THE FAR EAST MARKETS	
Location	Gas Supply (mmt)
Alaska	14
Australia	13
Indonesia (Natuna)	15
Oman	6
Papua New Guinea	6
Qatar	15
Sakhalin	10
Yemen	5
Total	84

The Qatar, Oman and Yemen projects appear to be in the advanced planning stages. The Indonesian project is the giant Natuna field, for which Exxon is the proposed operator. Given the large size of both the proposed Natuna and Prudhoe Bay projects, there is - at most - room for

only one of these as a source of supply in the Far East LNG market in the near term. At full development it would appear that the proposed Natuna project is more expensive per mcf delivered than the proposed North Slope project. However, the Natuna project can be staged in increments; staging the North Slope project severely affects its economics, especially with a Prince William Sound terminal.

The gas reserves in most of the countries supplying the Far East LNG market are very large and are expanding. Much of this gas was found in the course of exploring for oil. These gas supplies are more than ample for current markets. If deliberate exploration for gas ensued, it is likely that these gas reserves would increase substantially. The following table shows 1993 year-end gas reserves for selected countries.

CURRENT RESERVES OF MAJOR FAR EAST MARKET LNG SUPPLIERS	
Country	Reserves (tcf)
Abu Dhabi	177
Australia	100
Indonesia	89
Malaysia	72
Qatar	236
Total	674

Alaska has about 35 tcf in discovered reserves on the North Slope.

If demand in the Far East LNG market continues to grow 6% annually, the demand in 2005 will

be 100 mmt. Given apparent lower cost supplies of 84 mmt from existing, under construction, and low cost expansion sources, this leaves 16 mmt for new grass roots suppliers. At a 14 mmt minimum, an Alaskan project would have to capture 88% of the projected unfilled demand in 2005 to be able to fit into the market. Using the same assumptions, the demand in 2010 would be 130 mmt. Of this, 46 mmt would be available for grass roots projects for which construction has not yet commenced; a new Alaska project coming on line in 2010 would have to capture 30% of this projected unfilled demand.

3. The Pipeline Economic Disadvantage in Competing for a Place in the Market.

Of all the grass roots projects, Alaska is the only one which requires a major pipeline to bring the gas to tidewater. Nearly half of the total anticipated construction cost for the proposed Alaska project is attributable to the pipeline. The pipeline is a burdensome one-time, up-front cost that places the proposed Alaska project at a competitive disadvantage.

The proposed Alaska gas project only achieves the economies of scale which make it feasible at its full 14 mmt proposed capacity. While many of the competing projects also have comparable per unit costs, they attain those costs at much lower production levels. This is particularly true for the projects proposed in Qatar, Oman and Yemen. The need to cover the costs for the one-time, up-front pipeline investment is what makes the proposed Alaska project different. It may only be economic if its sponsors can begin the project at full capacity. Placing 14 mmt at once in the Far East LNG market may be difficult, given that multiple buyers will need to simultaneously commit

to the project.

Increments to existing projects have a "nimbleness" advantage to big new baseload, grass roots projects. Suppose there is just enough room in the marketplace in 2005 for the proposed Alaska project - 14 mmt. If any small addition to an existing project captures *any* part of the 14 mmt demand in the marketplace, the Alaska project may not be able to make a go of it. Furthermore, proposed increments to already existing LNG projects in most cases have a per unit cost advantage over the per unit costs of new grass roots projects.

Projects without major pipelines do not necessarily require as high a proportion of their investment up front. Ships and liquefaction facilities can be added in increments. Pipeline capacity cannot easily be added in increments. Therefore, projects which require a high proportion of investments in pipelines must capture bigger increments in the developing markets to be economic. This necessarily provides any project without a substantial pipeline leg an advantage. For this reason the producers have looked - and will continue to look - carefully at the proposed western route. Even though the tanker costs, the offshore loading terminal costs and the risk of supply disruptions pertinent to the proposed western route would be higher, reducing the proposed project's pipeline cost might make it possible to achieve competitive costs at reduced production levels. The western route project might well be economic with initial volumes well below 14 mmt. Obviously if the required initial amounts are smaller, it would be much easier to fit such a project into the market.